2.0 PROGRAM TECHNOLOGIES AND STATE APPLICABILITY

2.1 INTRODUCTION

This chapter provides detailed descriptions of leading technologies and associated R&D projects planned and anticipated under the Carbon Sequestration Program. This chapter also summarizes the current results of ongoing efforts to characterize existing CO_2 sources and potential repositories (sinks) and it describes the applicability of leading technologies by state.

Finally, the chapter presents a series of model projects that are representative of the leading technologies anticipated for field or pilot tests and potential implementation during future phases of the Program. The model projects consist of hypothetical facilities that would be necessary to implement the objectives of each respective project, including assumptions about land requirements, process components, supporting facilities, and construction aspects. To the extent practicable, the hypothetical projects have been conceived as sufficiently generic to be located in any region of the country. However, it is expected that the process demands and waste streams of respective model projects will create challenges that may affect their future siting.

Detailed model project descriptions are provided for those technologies that are in further stages of development. These would be more likely to be included in the pilot field validation testing of the Phase II Program, and potentially commercially deployed in the future at a much larger scale. Information summarized for each of the technologies in a model project includes general design and operating parameters of the project, environmental aspects, utility requirements, site requirements and operations, and construction requirements.

Model projects have been developed for:

- post-combustion CO_2 capture;
- CO_2 compression and transport;
- geologic sequestration options, including coal seam, basalt formation, enhanced oil recovery (EOR), and saline formation;
- co-sequestration of CO_2 and hydrogen sulfide (H_2S) in both Integrated Gasification Combined Cycle (IGCC) power plant and sour associated gas production cases; and
- reforestation of formerly mined lands.

Although not a DOE-NETL research area, a CO_2 compression and transport model project was developed to characterize all potential impacts of carbon sequestration from sources to sinks.

For other DOE-NETL technologies that are still in the early stages of R&D, detailed model project characterizations were not prepared. For those technologies, brief technology description summaries are presented in Appendix B. These R&D technologies include pre-combustion decarbonization, oxyfuel combustion, sequestration in other geologic formations, ocean sequestration (which is no longer investigated by the Program), breakthrough concepts, and co-sequestration of CO_2 with nitrogen oxides (NO_X) and sulfur dioxide (SO_2) from pulverized coal boilers. Also, a model project was not developed for agricultural terrestrial sequestration, as the USDA primarily leads that area of technology development.

2.2 PROGRAM TECHNOLOGY DESCRIPTIONS

DOE-NETL's core R&D efforts are focused in five key areas:

- CO_2 Capture
- Sequestration
- Monitoring, Mitigation, and Verification (MM&V)
- Breakthrough Concepts
- Non-CO_2 Greenhouse Gas (GHG) Mitigation

The portfolio of R&D efforts has two primary objectives: (1) lowering the cost and energy penalty associated with CO_2 capture from large point sources; and (2) improving the understanding of factors affecting CO_2 storage permanence and capacity in geologic formations, terrestrial ecosystems, and oceans. For both objectives, research is aimed at broadening the potential implementation of sequestration technology beyond early niche opportunities.

Figure 2-1 illustrates the relationships among these technologies and a relative timeline for their implementation.

2.2.1 Post-Combustion CO_2 Capture

Post-combustion capture involves the removal of CO_2 from the flue gas produced from fossil-fueled power plants, such as coal-fired or natural gas fuel. The key technical issues with this approach are that flue gas is usually near atmospheric pressure, and the CO_2 concentration is low (Klara and Srivastava, 2002). Flue gas from a pulverized coal-fired (PC) boiler is exhausted at 10-15 psi and contains 12-18 percent CO_2 by volume. The low partial pressure of CO_2 results in only a small driving force for traditional adsorption/absorption processes. While post-combustion CO_2 capture may not have the greatest potential for step-change reductions in separation and capture costs, it has the greatest near-term potential for reducing emissions. This is because post-combustion processes can be retrofitted to existing facilities, and the U.S. has 300 gigawatts (GW) of PC boiler capacity (NETL, 2005b).

2.2.1.1 Advanced Amine Absorption

The conventional technology for post-combustion CO_2 capture is amine scrubbing, in which a solution of amine and water is contacted with flue gas in a contactor unit. The amine and the CO_2 undergo a chemical reaction forming a CO_2-rich amine that is soluble in water. The CO_2-rich amine solution is then pumped to a regenerator where it is heated. This reverses the chemical reaction and releases pure CO_2 gas. The recovered amine is then recycled to the flue gas contactor. Both primary and secondary amines are used in CO_2 capture processes. Monoethanolamine (MEA), considered to be the state-of-the-art technology, gives fast rates of absorption and favorable equilibrium characteristics. Secondary amines, such as diethanolamine (DEA), also exhibit favorable absorption (NETL, 2004c).

A major problem associated with amine absorption is the degradation of the solvent through irreversible side reactions with SO_2 and other flue gas components resulting in solvent loss (Klara and Srivastava, 2002). In high concentrations, MEA is corrosive and is therefore typically diluted with water in these absorption systems. Due to the presence of the water, the amine solution requires significant energy for regeneration and also delivers CO_2 at low pressure. Significant R&D work is needed on membrane contactors to improve chemical compatibility with alkanolamines and high-temperature resistance. Researchers have an opportunity to optimize existing solvents or develop new solvents and system components to reduce total capital and operating costs.

Advanced solvents will be prepared by chemical treatment of high surface oxide materials with various amine compounds. Tasks include the modification of oxidized solid surfaces, chemical characterization of the amine-enriched sorbents, determination of CO_2 capture capacity, and examination of the performance durability of amine-enriched adsorbents. R&D tasks are also needed to optimize chemical scrubbing processes for CO_2 separation, develop improved gas-liquid mass transfer, develop improved amine absorbent systems that require less thermal energy for regeneration, increase the loading of the absorbent within the aqueous amine solution, and reduce the content of water in the amine solution (NETL, 2004a and 2004b).

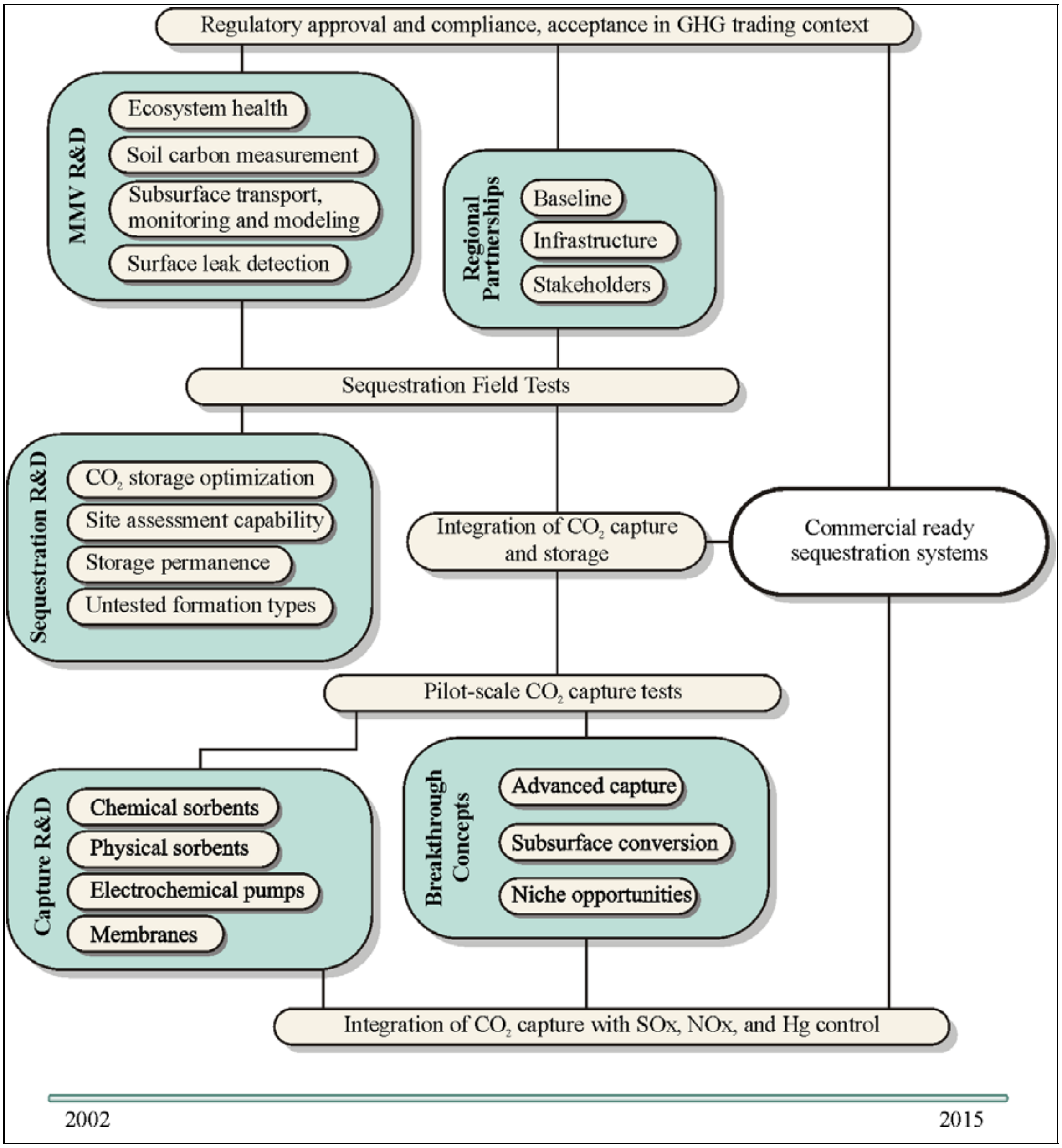


Figure 2-1. Carbon Sequestration Program Technologies and Timeline

2.2.2 Sequestration

Sequestration encompasses all forms of carbon storage, including storage in geologic formations and terrestrial ecosystems. Geologic sequestration is the placement of CO_2 or other greenhouse gases into subsurface porous and permeable rocks in such a way that they remain permanently stored. Terrestrial sequestration relies on natural processes in plants and microorganisms that take up CO_2 and convert the carbon into vegetative biomass or minerals.

2.2.2.1 Geologic Sequestration Overview

Geologic storage of anthropogenic (man-made) CO_2 as a GHG mitigation option was first proposed in the 1970s, but little research was done until the early 1990s. In a little over a decade, geologic storage of CO_2 has grown from a concept of limited interest to one that is quite widely regarded as a potentially important mitigation option. Technologies that have been developed for and applied by the oil and gas industry can be used for the injection of CO_2 in deep geologic formations. Well-drilling technology, injection technology, computer simulation of reservoir dynamics, and monitoring methods can potentially be adapted from existing applications to meet the needs of geologic storage (IPCC, 2005).

Types of geologic formations capable of storing CO_2 include oil and gas bearing formations, saline formations, basalts, deep coal seams, and oil- or gas-rich shales. Not all geologic formations are suitable for CO_2 storage; some are too shallow and others have low permeability (the ability of rock to transmit fluids through pore spaces) or poor confining characteristics. Formations suitable for CO_2 storage have specific characteristics such as thick accumulations of sediments or rock layers, permeable layers saturated with saline water (saline formations), extensive covers of low porosity sediments or rocks acting as seals, (caprock), structural simplicity, and lack of faults (IPCC, 2005). Figure 2-2 illustrates sequestration within a saline formation.

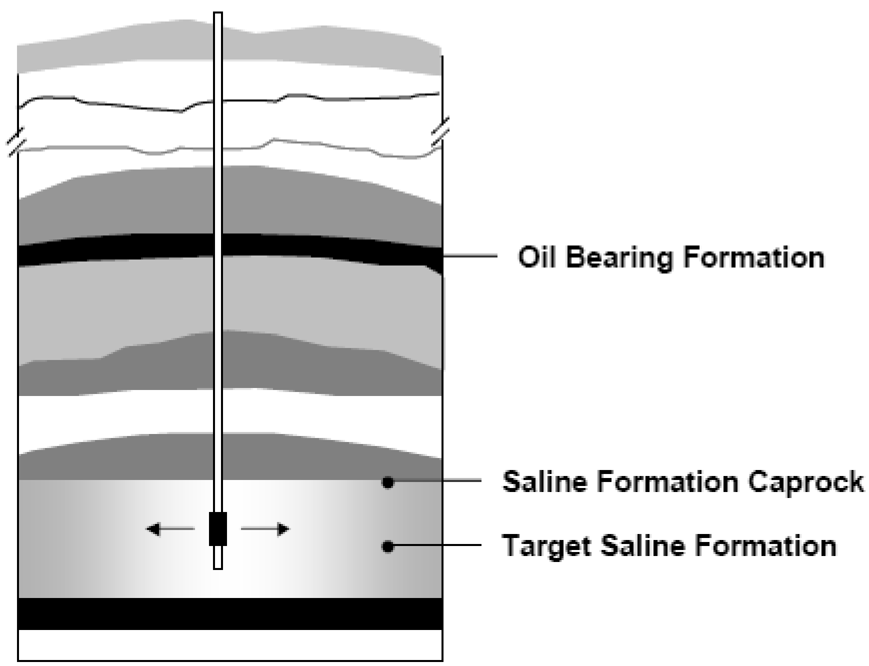


Figure 2-2. Geologic Sequestration Example - Deep Saline Formation

The CO_2 would be compressed into a supercritical state and injected into a deep geologic formation. The injected CO_2 would displace the existing water occupying the formation's pore space. Without this displacement, CO_2 could only be injected by increasing the formation's fluid pressure, which could result in formation fracturing. If a formation's fluid pressure is too high, the sequestration process may require installation of extraction wells that remove water from the formation.

Supercritical CO_2 - CO_2 usually behaves as a gas in air or as a solid in dry ice. If the temperature and pressure are both increased (above its supercritical temperature of 88ºF [31.1ºC] and 73 atmospheres [1,073 psi]), it can adopt properties midway between a gas and a liquid, such that it expands to fill its container like a gas, but has a density like that of a liquid.

To increase the storage potential, CO_2 would be injected into very deep formations where it could maintain its dense supercritical state. The fate and transport of CO_2 in the formation would be influenced by the injection pressure, dissolution in the formation water, and upward migration due to CO_2's buoyancy.

Injection would raise the fluid pressure near the well allowing CO_2 to enter the pore spaces initially occupied by the saline water within the formation. Once injected, the spread of CO_2 would be governed by the following primary flow, transport and trapping mechanisms:

- Fluid flow (migration) in response to pressure gradients created by the injection process;
- Fluid flow (migration) in response to natural groundwater flow;
- Buoyancy caused by the density differences between CO_2 and the groundwater;
- Diffusion;
- Dispersion and fingering (localized channeling) caused by formation heterogeneities and mobility contrast between CO_2 and the groundwater;
- Dissolution into the formation groundwater or brine;
- Mineralization;
- Pore space trapping; and
- Adsorption of CO_2 onto organic material.

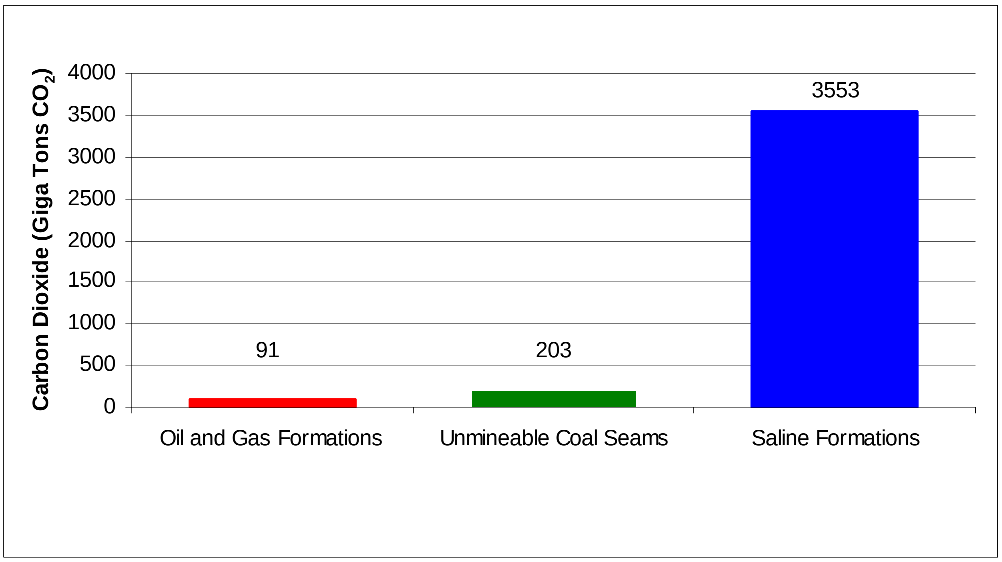
The magnitude of the buoyancy forces that drive vertical flow depends on the type of fluid in the formation. When CO_2 is injected into a deep saline formation in a liquid or liquid-like supercritical dense phase, it is only somewhat miscible in water. Because supercritical CO_2 is much less viscous than water (by an order of magnitude or more), it would be more mobile and could migrate at a faster rate than the saline groundwater. In saline formations, the comparatively large density difference (30 to 50 percent) creates strong buoyancy forces that could drive CO_2 upwards.

To provide secure storage (e.g., structural trapping), a lower permeability layer (caprock) would act as a barrier and cause the buoyant CO_2 to spread laterally, filling any stratigraphic or structural trap it encounters. As CO_2 migrates through the formation, it would slowly dissolve in the formation water. In systems with slowly flowing water, reservoir-scale numerical simulations show that, over tens of years, up to 30 percent of the injected CO_2 would dissolve in formation water. Larger basin-scale simulations suggest that, over centuries, the entire CO_2 plume would dissolve in formation water. Once CO_2 is dissolved in the formation water, it would no longer exist as a separate phase (thereby eliminating the buoyant forces that drive it upwards), and it would be expected to migrate along with the regional groundwater flow.

As migration through a formation occurs, some of the CO_2 would likely be retained in the pore space, commonly referred to as "residual CO_2 trapping." Residual trapping could immobilize large amounts of the CO_2. While this effect is formation-specific, researchers estimate that 15 to 25 percent of injected CO_2 could be trapped in pore spaces, although over time much of the trapped CO_2 dissolves in the formation water (referred to as “dissolution trapping”). The dissolved CO_2 would make the formation water more acidic, with pH dropping as low as 3.5, which would be expected to dissolve some mineral grains and mineral cements in the rock, accompanied by a rise in the pH. At that point, some fraction of the CO_2 may be converted to stable carbonate minerals (mineral trapping), the most permanent form of geologic storage. Mineral trapping is believed to be comparatively slow, taking hundreds or thousands of years to occur (IPCC, 2005).

To ensure the safe storage of sequestered CO_2, a monitoring and mitigation strategy would be implemented. The purposes of monitoring include assessing the integrity of plugged or abandoned wells in the region; calibrating and confirming performance assessment models; establishing baseline parameters for the storage site to ensure that CO_2-induced changes are recognized; detecting microseismicity associated with the storage project; measuring surface fluxes of CO_2; and designing and monitoring remediation activities.

Figure 2-3 illustrates the relative capacity of various geologic sequestration approaches. Through the development of optimized field practices and technologies, the Program seeks to quantify and improve the storage capacity of all potential formations (NETL, 2005b).



Source: NETL, 2007.

Figure 2-3. Carbon Dioxide Capacity Estimates for the U.S. and Canada of Areas Assessed by the Carbon Sequestration Regional Partnerships

2.2.2.2 Sequestration in Unmineable Coal Seams

> With their large internal surface areas, coal seams can store several times more CO_2 than the equivalent volume of a conventional gas formation.

An attractive option for disposal of CO_2 is geologic sequestration in deep, unmineable coal seams. Coalbed methane (CBM) recovery is the fastest growing source of domestic natural gas supply and accounted for 8 percent of domestic production in 2002. Enhanced CBM (ECBM) recovery is usually achieved by flooding the coal seam with nitrogen. Because CO_2 preferentially adsorbs onto the surface of coal and releases methane, it offers an attractive alternative to nitrogen. With their large internal surface areas, coal seams can store several times more CO_2 than the equivalent volume of a conventional gas formation. These formations have high potential for adsorbing CO_2 on coal surfaces, and the displaced methane offers a valuable byproduct to reduce the overall cost of sequestration. The maximum capacity for CO_2 ECBM in the U.S. has been estimated at 90 billion metric tons of CO_2, but 44 percent of this capacity is in Alaska. The ultimate commercial deployment of ECBM carbon sequestration may depend in part on the availability of surface and mineral rights, future mining technology developments and coal prices, and CO_2 injectivity rates.

One problem with CO_2 ECBM is the tendency for coal to swell in volume as it adsorbs CO_2, which restricts the flow of CO_2 into the formation and impedes methane recovery (NETL, 2004a).

Several R&D projects and large-scale field tests are currently underway to investigate sequestration mechanisms in coal seams.

2.2.2.3 Sequestration in Depleted Oil and Gas Reserves

> The CO_2 storage capacity of domestic oil and gas fields could potentially sequester 30 years worth of U.S. emissions.

Approximately 32 million tons per year of CO_2 are injected into depleting oil formations in the U.S. as part of EOR operations. The typical storage rate is 2,000 scf CO_2 per barrel oil recovered, but current practices are not directed toward optimizing CO_2 storage (NETL, 2005a). The CO_2 storage capacity of domestic oil and gas fields has been estimated at approximately 150 billion metric tons of CO_2, which represents 30 years worth of U.S. emissions (NETL, 2004a). It is not yet possible to predict storage volumes, formation integrity, and permanence with confidence over long periods of time. Many important issues must be addressed, such as interactions between CO_2 and formation rock and other fluids, as well as the monitoring and verification of fluids (including CO_2) in underground oil and gas fields. Large-scale demonstrations are needed to confirm practical considerations, such as economics, safety, stability, permanence and public acceptance (Klara, et. al., 2003).

Early tests involve sequestration experiments in which collateral benefits are likely, such as storing CO_2 in depleted oil and gas fields, where additional hydrocarbons may be produced. Because such formations are generally gas tight (i.e., where leakage of natural gas and other associated gases is negligible), the risk of leakage is expected to be minimal. These geologic traps by their very nature, having confined accumulations of oil and natural gas over millions of years, have proven their ability to contain fluids and gas. Additionally, if storage pressures of CO_2 stay below original formation pressures and there is integrity of existing well bores, there should be no leakage (IOGCC, 2005).

These geologic structures that originally contained the oil and natural gas should be able to permanently sequester the injected CO_2, provided the integrity of the structure is maintained. Because of seismic studies, the geologic structure and physical properties of many oil and gas fields are well understood. For example, one commercial CO_2 EOR operation in the U.S. began in 1986, and leakage of CO_2 via well bores or through the formation cap is considered to be negligible, and monitoring wells are used to track movement of injectant within the formation (NETL, 2004d). Also, monitoring of the Weyburn commercial scale CO_2 EOR project (see description in 3.3.5.2) which utilizes observation wells, 3D seismic, cross-well seismic, soil monitors, and gas tracers, soil sampling indicates no CO_2 leakage from the formation and there is no independent evidence to suggest any significant volume of CO_2 has migrated above the formation (NETL, 2005).

These long term geologic storage issues, such as leakage of CO_2 through old well bores, faults, seals, or diffusion out of the formation, need to be addressed. Many tools exist or are being developed for monitoring geologic sequestration of CO_2, including well testing and pressure monitoring; tracers and chemical sampling; surface and bore hole seismic; and electromagnetic/geomechanical meters. However, the spatial and temporal resolution of these methods may not be sufficient for performance confirmation and leak detection. Therefore, further monitoring needs include:

- High resolution mapping techniques for tracking migration of sequestered CO_2
- Deformation and microseismicity monitoring
- Remote sensing for CO_2 leaks and land surface deformation (Klara, et al., 2003)

More details on geologic sequestration MM&V technologies are presented in Section 2.2.3.

The potential for enhanced oil and gas production helps mitigate sequestration costs. Most EOR projects in the U.S. are in the Permian Basin of Texas, and most of the CO_2 used is transported by pipeline from natural CO_2 formations in Colorado, New Mexico, and Wyoming. It is anticipated that recovery of CO_2 from flue gas of coal burning power plants could be profitable for regional EOR use (Klara, et al., 2003).

2.2.2.4 Sequestration in Saline Formations

Deep saline formations are among the largest and most widely available potential formations for long-term CO_2 storage. About two-thirds of the U.S. is underlain by deep saline formations.

Saline formations are layers of porous rock that are saturated with brine, or highly saline water (NETL, 2004a). Deep saline formations are among the largest and most widely available potential formations for long-term CO_2 storage. About two-thirds of the U.S. is underlain by deep saline formations (Bergman and Winter, 1995), and usable formations are known to exist under the oceans. These formations have an estimated CO_2 adsorption capacity of between 320 billion and 10 trillion tons. Moreover, many of these formations are located in close proximity to major point sources of CO_2 emissions, such as fossil-fuel power plants, which offers the benefit of reducing costs for transportation of CO_2 to the injection site (NETL, 2002). Because the brine water from such formations is typically not suitable for irrigation and other uses, injection of CO_2 and its subsequent aqueous dissolution does not affect the potential use of the water. However, there are many uncertainties associated with the reactions that may occur between CO_2, brine, and minerals in the surrounding strata (Klara, et al., 2003). (Note: Brine is defined as water containing more dissolved inorganic salt than typical seawater, or greater than 35,000 ppm total dissolved salts [TDS], as compared to fresh water containing less than 1000-2000 ppm TDS [Schlumberger, 2005 and USGS, 2003]. Varying grades of saline water have salt concentrations between those two levels. Within this document, the terms brine formation and saline formation are used synonymously, and imply the presence of either brine [>35,000 ppm TDS] and/or highly saline water [10,000-35,000 ppm TDS]).

Two key issues distinguish CO_2 sequestration in saline formations from sequestration in oil and gas fields. First, oil and gas fields result from the presence of a structural or stratigraphic trap. This same trap is likely to retain CO_2 as well. Identification of such effective traps may be more difficult in aqueous formations and may require new approaches for establishing the integrity and extent of a caprock. Second, injection of CO_2 into a saline formation is unlikely to be accompanied by removal of water from the formation. In the case of EOR, oil and brine are simultaneously withdrawn while CO_2 is injected. Injection of CO_2 into a saline formation, on the other hand, will lead to an increase in formation pressure over a large area. Whether, and to what extent, large-scale pressurization will affect caprock integrity, cause land surface deformation, and induce seismic hazards, must be better understood to design safe and effective sequestration in saline formations. Another issue pertains to the acceptable leakage rate from the formation into overlying strata (DOE, 1999). Furthermore, sequestration in a saline formation does not offer the value-added benefit of enhanced hydrocarbon production. The structural and stratigraphic traps of oil and gas fields should contain the CO_2 injected as part of an EOR project, so long as pathways to the surface or to adjacent formations are not created by over-pressuring the formation, by fracturing out of the formation at wells, or by

Leakage of injected CO_2 from a deep saline formation into overlying formations is a relevant concern, particularly where drinking water sources are in the vicinity.

leaks around wells and through abandoned well bores. Although EOR has the benefit of sequestering CO_2 while increasing production from active oil fields, and its technology for CO_2 injection is commercially proven, in the long term the volume of CO_2 sequestered as part of the EOR phase of those sequestration projects may not be large (DOE, 1999). Once the EOR/sequestration project's oil fields are fully depleted over time, their long term CO_2 injection and storage concerns will be similar to those of saline formations.

Injection into a deep saline formation and potential leakage into overlying formations is a relevant concern, particularly where drinking water sources are in the vicinity. Most studies to date have been concerned with breaching the caprock, formation capacity and injectivity, and CO_2, water and host/seal rock interaction. Less work has been done to understand the effects of displacing the saline water from the deeper basin into shallower outcrops, subcrops, or into freshwater regions of the same formation. Injection is not purely displacement due to the dissolution of CO_2 into water, i.e., a unit volume of CO_2 does not necessarily displace a unit volume of water. Depending on the dissolution time and CO_2 solubility of the water, only a fraction of the water is displaced. The outer perimeter of a basin is extremely large compared to a single injection well, or a field of injection wells; therefore, the change in position of a freshwater/saline water interface is likely very small.

Recent analytical estimations using pressure transient analysis indicate only very small pressure (<1 psi) changes occur 30-40 miles away from a single well after 30 years of injecting 1 MMT CO_2/year; additionally, no appreciable change in velocity or interface location was predicted for 100 years of 300 million metric tons (MMT) CO_2/year (approximately the entire Illinois Basin's current stationary source CO_2 emissions). These preliminary simulations show that the injection of large volumes of CO_2 in a saline formation has an inconsequential effect on the position of the fresh-salt water interface after decades of continuous injection (Frailey, et al., 2005).

2.2.2.5 Sequestration in Basalt Formations

Basalt is a hard, black volcanic rock and is the most common rock type in the Earth's crust (outer 10 to 50 kilometers). Most of the ocean floor is made of basalt. Large areas of lava called "flood basalts" are found on many continents. For example, the Columbia River basalts erupted 15 to 17 million years ago and cover most of southeastern Washington and regions of Oregon and Idaho.

Major basalt formation may be attractive for carbon sequestration in the Pacific Northwest, the Midwest, the Southeastern U.S. and several other locations. Basalt formations have unique properties that can chemically trap injected CO_2, effectively and permanently isolating it from the atmosphere (NETL, 2004a).

2.2.2.6 Co-Sequestration of CO_2 and H_2S

Natural gas processing from sour gas fields results in a CO_2 waste stream laden with H_2S. This acid gas is injected into deep saline formations and depleted oil or natural gas formations at 41 locations in Canada, and at approximately 20 sites in Michigan, New Mexico, Oklahoma, Texas, and Wyoming in the U.S. In Canada, a total of 2.5 million tons of CO_2 and 2 million tons of H_2S have been injected through the end of 2003. Co-sequestration of these gases is appropriate for EOR operations or geologic sequestration in saline formations. In addition, IGCC power generation technology, which produces a combined CO_2/H_2S emission stream, provides substantial environmental benefits as opposed to conventional coal burning power technology. To incorporate IGCC technology and support program application to sour gas processing, two model project cases of co-sequestration capture of CO_2 and H_2S have been developed: (1) IGCC power plant; and (2) sour associated gas production.

2.2.2.7 Terrestrial Sequestration

Terrestrial sequestration relies on natural processes in plants and microorganisms to take up CO_2 and convert the carbon into vegetative biomass or minerals.

Terrestrial ecosystems, which include both soil and vegetation, are widely recognized as a major biological "scrubber" for CO_2. Terrestrial sequestration is defined as either the net removal of CO_2 from the atmosphere or the prevention of CO_2 emissions from leaving terrestrial ecosystems.

Terrestrial carbon sequestration can be enhanced in four ways:

- reversing land use patterns;
- reducing the decomposition of organic matter;
- increasing the photosynthetic carbon fixation of trees and other vegetation; and
- creating energy offsets using biomass for fuels and other products.

The terrestrial biosphere is estimated to sequester large amounts of carbon, about 2 billion tons annually. The total amount of carbon stored in soils and vegetation throughout the world is estimated to be roughly 2,000 billion tons (NETL, 2003).

Because the U.S. has vast agricultural and forest resources, policymakers have looked to terrestrial sequestration as an option for reducing net GHG emissions from stationary sources and vehicles. Numerous tree-planting projects have been undertaken by industry, and scientists are experimenting with agricultural practices that enhance carbon storage in soils. In the near-term, sequestration of carbon in terrestrial ecosystems offers a low-cost means of reducing CO_2 in the atmosphere with significant ancillary benefits, including restored natural environments for plants and wildlife, reduced runoff, and increased domestic production of agriculture and forest products (NETL, 2005a).

Currently, terrestrial uptake offsets roughly one third of global anthropogenic CO_2 emissions. The uptake from domestic terrestrial ecosystems is expected to decrease 13 percent over the next 20 years as northeastern forests mature. Opportunities for enhanced terrestrial sequestration include 1.5 million acres of land damaged by past mining practices, 32 million acres of Conservation Reserve Program (CRP) farmland, and 120 million acres of pastureland (NETL, 2005b).

DOE's core R&D program currently is limited to the integration of energy production, conversion, and use with land reclamation (NETL, 2005b). Specifically, this involves reforestation and the amendment of damaged soils using solid residuals from coal combustion where possible. The Program's activities are closely coordinated with efforts undertaken by the USDA, the U.S. Forestry Service, the Office of Surface Mining, and the DOE Office of Science, Center for Enhancing Carbon Sequestration in Terrestrial Ecosystems (CSiTE). NETL is participating in OSRME's Appalachian Regional Reforestation Initiative which is designed to promote the Forestry Reclamation Approach (FRA) on abandoned and recently mined lands. This FRA is being applied in several of NETL's core R&D projects.

2.2.3 Monitoring, Mitigation, and Verification (MM&V)

MM&V is defined as the capability to:

- measure the amount of CO_2 stored at a specific sequestration site;
- monitor the site and mitigate the potential for leaks or other deterioration of storage integrity over time; and
- verify that the CO_2 is being stored and is not harmful to the host ecosystem (NETL, 2005b).

Reliable, affordable and practical methods of MM&V are needed for projects to sequester carbon in underground storage sites, and in forests and soils.

Monitoring is likely to be required as part of the permitting process for underground injection and would be used for a number of purposes, including but not limited to:

- tracking the location of the plume of injected CO_2;
- ensuring that injection and abandoned wells are not leaking; and
- for verification of the quantity of CO_2 that has been injected.

Additionally, depending on site-specific conditions, monitoring may also be required to ensure that natural resources such as groundwater and ecosystems are protected and that local populations are not exposed to unsafe concentrations of CO_2 (Benson, 2002).

MM&V can be divided into three broad categories: subsurface, soils, and aboveground (NETL, 2004a). Subsurface MM&V involves tracking the fate of the CO_2 within the geologic formations underlying the earth and possible migration or leakage to the surface. Soils MM&V involves tracking carbon uptake and storage in the first several feet of topsoil and tracking potential leakage pathways into the atmosphere from the underlying geologic formation. This area of research is especially challenging due to the difficulty in detecting small changes in CO_2 concentration above background concentration emissions (~370 parts per million (ppm)) that already exist in the atmosphere. Aboveground MM&V is specific to terrestrial sequestration and involves quantification of the aboveground carbon stored in vegetation.

MM&V includes the development of protocols and methodologies for calculating the net avoided CO_2 emissions from systems associated with carbon capture, transport, and storage, while specifically considering and comparing different levels of parasitic losses in generating capacity (to provide power for the added processes) and methods for replacing capacity. Current MM&V practices are time-consuming and costly, and this situation is further complicated by the fact that standard, acceptable protocols for carbon measurement and accounting do not exist. Advanced technologies for higher resolution CO_2 detection are being tested at several sites, including the Sleipner, Weyburn, and West Pearl Queen formations. Effective MM&V technologies will be essential for the success of a potential future carbon emissions credit trading market. As an example of the future potential for such a market, Ontario Power Generation bought 6 million tons of CO_2 emissions credits from Blue Source LLC in July 2002. Blue Source provided the emission reductions from oil field carbon sequestration projects in Texas, Wyoming, and Mississippi (NETL, 2005b).

2.2.3.1 Geologic Sequestration MM&V

Subsurface MM&V systems draw upon the significant capabilities developed for fossil resource exploration and production over the past century. Work in subsurface MM&V options includes surface-to-borehole seismic, micro-seismic, and cross-well electromagnetic imaging devices to characterize storage formation properties and changes after CO_2 injection. Aboveground MM&V technology is less mature and is focused on detecting leaks or deterioration in the storage formation and assessing ecological impacts of geologic carbon storage (NETL, 2005b).

> As seismic imaging can have an adverse impact on biological resources, potential impacts and mitigation measures are discussed in Section 4.4 "Biological Resources".

Monitoring methods will depend on the type of geologic sequestration being performed and the geologic conditions of the project area. For example, depleted oil and gas fields are particularly suitable for CO_2 storage as they have been shown by the test of time that they can effectively store buoyant fluids, such as oil, gas and CO_2 (Benson, 2002). Storage in deep saline formations is in principle the same as storage in oil or gas fields, but the geologic seals that would keep the CO_2 from rising rapidly to the ground surface need to be characterized and demonstrated to be suitable for long-term storage (Benson, 2002). Coal beds offer the potential for a different type of storage where CO_2 becomes chemically bound to the solid coal matrix. Over hundreds to thousands of years, some fraction, including possibly all of the CO_2, is expected to dissolve in the formation fluids. Once dissolved or reacted to form minerals, CO_2 is no longer buoyant and consequently, would no longer rise rapidly to the ground surface in the absence of s suitable geologic seal (Benson, 2002).

Approaches for monitoring geologic storage of CO_2 are provided in Table 2-1.

Table 2-1. Monitoring Approaches for Geologic Sequestration of CO_2

Parameter	Monitoring Approaches
CO_2 plume location	*2 and 3-D seismic reflection surveys* *Wellbore to surface and cross wellbore seismic measurements* *Electrical and electromagnetic methods* *Land surface deformation using satellite imaging or tiltmeters* *Gravity methods* *Formation pressure monitoring* *Wellhead and formation fluid sampling* *Natural and introduced tracers*
Providing early warning that a storage site may be failing	*2 and 3-D seismic reflection surveys* *Wellbore to surface and cross wellbore seismic measurements* *Land surface deformation using satellite imaging or tiltmeters* *Injection well and formation pressure monitoring*
CO_2 concentrations and fluxes at the ground surface	*Real-time IR based detectors for CO_2 concentrations* *Air sampling and analysis using gas chromatography or mass spectrometry* *Eddy flux towers* *Monitoring for natural and introduced tracers*
Injection well condition, flow rates and pressures	*Borehole logs, including casing integrity logs, noise logs, temperature logs, and radiotracer logs* *Wellhead and formation pressure gauges* *Wellbore annulus pressure measurements* *Orifice or other differential flow meters* *Surface CO_2 concentrations near the injection wells*
Solubility and mineral trapping	*Formation fluid sampling using wellhead or downhole samples - analysis of CO_2, major ion chemistry and isotopes* *Monitoring for natural and introduced tracers, including partioning tracers*
Leakage up faults and fractures	*2 and 3-D seismic reflection surveys* *Wellbore to surface and cross wellbore seismic measurements* *Electrical and electromagnetic methods* *Land surface deformation using satellite imaging or tiltmeters* *Formation and aquifer pressure monitoring* *Groundwater and vadose zone sampling*
Groundwater quality	*Groundwater sampling and geochemical analysis from drinking water or monitoring wells* *Natural and introduced tracers*
CO_2 concentrations in the vadose zone and soil	*Soil gas surveys and gas composition analysis* *Vadose zone sampling wells and gas composition analysis*
Ecosystem impacts	*Hyperspectral geobotanical monitoring* *Soil gas surveys* *Direct observation of biota*
Micro-seismicity	*Passive seismic monitoring using single or multi-component seismometers*

Source: Benson, 2002.

Although there are no model projects developed for MM&V methods, seismic imaging can have adverse impacts on biological resources. The potential impacts associated with seismic imaging and possible mitigation measures will be discussed in Section 4.5 “Biological Resources”.

2.2.3.2 Terrestrial Sequestration MM&V

Methods for monitoring and verifying the amount of carbon stored in terrestrial ecosystems are slow and imprecise. Because terrestrial sequestration relies on natural processes, public health and safety issues are not driving the need for MM&V. However, precise and reliable measurements of both aboveground carbon and soil carbon will be needed to enable the use of terrestrial sequestration in emissions trading applications. Roughly 8 MMT of carbon sequestered in terrestrial ecosystems was traded in 2002, requiring preliminary estimations of baseline carbon stocks and projected storage. Methods for modeling and tracking aboveground carbon, such as 3D videography, correlations between soil and aboveground carbon, and infield technology to measure soil and other below-ground carbon will reduce the cost of establishing a baseline for carbon stocks. Current on-the-ground measurements are accurate within plus or minus 5 to 30 percent, and can cost as little as $1 per ton net carbon offset (NETL, 2005b).

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2.3 CARBON DIOXIDE SOURCES AND SINKS

2.3.1 CO_2 Sources

Most U.S. anthropogenic CO_2 emissions result from the combustion of fossil fuels by power plants, industrial facilities, vehicles, and residential and commercial heating systems. Industrial sources of relatively pure CO_2 emissions are natural gas processing, ammonia production, and ethanol production. Another large source of CO_2 emissions is the calcination of limestone in cement production. Other sources include lime manufacture, limestone and dolomite consumption, soda ash manufacture and consumption, industrial CO_2 manufacture, and aluminum production. For the purposes of identifying CO_2 sources, this section focuses on and provides information about fossil-fueled power plants, natural gas processing, ammonia production, ethanol production, and cement production.

2.3.1.1 Fossil-Fueled Electric Plants

Based on the DOE Energy Information Administration's "Inventory of Electric Utility Power Plants in the U.S, 2000", there were 6,099 fossil fuel based electric plants in the U.S. in 2000 (EIA, 2000). These plants had a generation capability of over 430,000 mega-watts (MW) of electricity. In 2003, CO_2 emissions associated with electric utility plants equaled 2,408.9 MMT (EIA, 2003a). The top 10 states for the highest number of coal, gas or petroleum based electric power plants are (in descending order): Alabama, Kansas, Iowa, Texas, Florida, Missouri, Michigan, Ohio, Minnesota and Nebraska (see Table 2-2).

Table 2-2. Fossil-Fueled Electric Plants, Top 10 States (2000)[1]

State	Number of Fossil Fueled Electric Plants	Planned Additions (2001-2005)[2]
Alaska	509	15
Kansas	418	24
Iowa	400	25
Texas	375	withheld
Florida	335	25
Missouri	328	15
Michigan	326	withheld
Ohio	272	18
Minnesota	269	24
Nebraska	244	14

1 EIA reports available after 2000 provide data in terms of geographic regions that and does not provide data in terms of individual states.
2 Data provided on planned additional plants do not specify fuel type.

Source: EIA, 2000.

Although the number of electric power generating plants can be a good estimate of CO_2 capture and sequestration potential, the overall amount of CO_2 emissions from all energy sources within the states is also a good overall indicator of future sequestration potential. The DOE Energy Information Administration’s (EIA) 1989-2004 Estimated Emissions by State and Fuel Type report was reviewed to determine total CO_2 emissions from power plants at the state level. The data is presented as the total CO_2 emissions for Electric Utilities per state and the emissions for all sectors and all sources (i.e. coal, natural gas, petroleum, others) (see Table 2-3). Ohio leads the nation for CO_2 emissions from Electric Utilities generation, followed by Florida, Indiana, Texas and Kentucky. The state with the highest CO_2 emissions from all sources is Texas followed by Florida, Ohio, Pennsylvania and Indiana (EIA, 2005b).

Table 2-3. CO_2 Emissions in 2004 by State from Electric Utility Plants and All Sectors

State	Electric Utility (Million Metric Tons)	All Sources (Metric Tons)
Alabama	73.2	80.2
Alaska	2.9	4.7
Arizona	41.5	50.6
Arkansas	25.1	27.1
California	6.0	60.7
Colorado	35.6	39.6
Connecticut	0.0	10.3
Delaware	0.0	6.5
District of Columbia	0.1	0.0
Florida	114.4	130.1
Georgia	74.4	81.5
Hawaii	5.6	8.9
Idaho	0.0	1.3
Illinois	19.1	100.3
Indiana	109.0	118.9
Iowa	35.7	40.0
Kansas	37.2	37.3
Kentucky	75.1	87.3
Louisiana	24.2	58.1
Maine	0.0	7.0
Maryland	0.0	31.8
Massachusetts	1.0	26.1
Michigan	65.3	77.2
Minnesota	32.9	37.6
Mississippi	19.1	25.3
Missouri	74.5	75.9
Montana	0.4	19.1
Nebraska	20.6	20.7
Nevada	20.0	25.3
New Hampshire	5.5	8.2
New Jersey	1.9	21.3
New Mexico	30.6	30.9
New York	13.2	57.6
North Carolina	65.7	72.6
North Dakota	30.0	30.4
Ohio	116.9	123.1
Oklahoma	39.0	46.6
Oregon	4.4	9.1
Pennsylvania	17.4	121.6
Rhode Island	0.0	2.1
South Carolina	36.8	39.4
South Dakota	3.8	3.8
Tennessee	52.4	58.5
Texas	77.7	255.7
Utah	34.1	35.2
Vermont	0.0	0.0
Virginia	30.5	46.8
Washington	1.0	15.0
West Virginia	53.6	82.2
Wisconsin	43.9	49.4
Wyoming	43.3	45.5

Source: EPA, 2005b.

Since states vary greatly in terms of population, the relative CO_2 emissions on a per capita basis may provide a better idea of which states have the highest carbon intensity. Although some states export power to other states, normalizing CO_2 based on state population can be a useful, if not an entirely precise, measure of a state's relative CO_2 output.

The top ten states with the highest CO_2 emissions per capita based on the EIA 2005 Estimated Emissions by State and Fuel Type report and 2000 U.S. Census data are (in descending order): Wyoming, North Dakota, West Virginia, Kentucky and Indiana (see Table 2-4).

Table 2-4. CO_2 Emissions per Capita (from Electricity Production and All Sources)

State	Electric Utility (Metric Tons)	All Sources (Metric Tons)
Alabama	16.5	18.0
Alaska	4.7	7.5
Arizona	8.1	9.9
Arkansas	9.4	10.1
California	0.2	1.8
Colorado	8.3	9.2
Connecticut	0.0	3.0
Delaware	0.0	8.3
District of Columbia	0.1	0.0
Florida	7.2	8.1
Georgia	9.1	10.0
Hawaii	4.6	7.4
Idaho	0.0	1.0
Illinois	1.5	8.1
Indiana	17.9	19.6
Iowa	12.2	13.7
Kansas	13.9	13.9
Kentucky	18.6	21.6
Louisiana	5.4	13.0
Maine	0.0	5.5
Maryland	0.0	6.0
Massachusetts	0.2	4.1
Michigan	6.6	7.8
Minnesota	6.7	7.6
Mississippi	6.7	8.9
Missouri	13.3	13.6
Montana	0.5	21.2
Nebraska	12.0	12.1
Nevada	10.0	12.7
New Hampshire	4.5	6.6
New Jersey	0.2	2.5
New Mexico	16.8	17.0
New York	0.7	3.0
North Carolina	8.2	9.0
North Dakota	46.6	47.3
Ohio	10.3	10.8
Oklahoma	11.3	13.5
Oregon	1.3	2.7
Pennsylvania	1.4	9.9
Rhode Island	0.0	2.0
South Carolina	9.2	9.8
South Dakota	5.1	5.1

State	Electric Utility (Metric Tons)	All Sources (Metric Tons)
Tennessee	9.2	10.3
Texas	3.7	12.3
Utah	15.3	15.7
Vermont	0.0	0.0
Virginia	4.3	6.6
Washington	0.2	2.5
West Virginia	29.7	45.4
Wisconsin	8.2	9.2
Wyoming	87.6	92.0

Source: EPA, 2005b, U.S. Census 2005.

2.3.1.2 Natural Gas Processing Plants

CO_2 is produced as a byproduct of natural gas production and processing. Natural gas produced from natural gas wells (referred to as non-associated natural gas) and natural gas produced from crude oil wells (referred to as associated-dissolved natural gas) may contain naturally occurring CO_2 that must be removed from the natural gas in order for it to meet pipeline specifications for CO_2 content. A fraction of the CO_2 remains in the natural gas delivered to end-users by pipeline, and is emitted when the natural gas is combusted. However, the majority of the CO_2 is separated from natural gas at gas processing plants. CO_2 removed at gas processing plants is generally vented to the atmosphere. However, capture and sequestration of CO_2 from natural gas processing plants is already occurring in Wyoming and Texas. As of 2002, there were four gas processing plants that produce CO_2 for use in enhanced oil recovery (EPA, 2004).

In 2004, 17,993,520 million cubic feet of natural gas was processed in the U.S. About half the natural gas processing in the U.S. occurs in Texas, Wyoming and Oklahoma (EIA, 2005c). The top 10 states for natural gas processing are (in descending order of production): Texas, Wyoming, Oklahoma, New Mexico, Louisiana, Colorado, Kansas, Alabama, Utah and Michigan (see Table 2-5) (EIA, 2005c).

Table 2-5. Top Ten States for Natural Gas Processing in 2004

State	Million Cubic Feet
Texas	5,074,067
Wyoming	1,736,136
Oklahoma	1,604,709
New Mexico	1,397,934
Louisiana	1,293,204
Colorado	1,002,453
Kansas	350,413
Alabama	333,583
Utah	259,432
Michigan	212,276

Source: EIA, 2005c.

2.3.1.3 Ammonia Plants

Anhydrous ammonia is produced by the refinement of natural gas in the presence of steam and injected with air. A typical ammonia plant uses approximately 32,000 cubic feet of natural gas to produce one ton of ammonia (NH_3). After desulphurization of the gas, steam is induced to the process gas and passed through a catalyst in a heated reformer. Air is then injected, and the gas is sent through 2 separate catalyst beds for CO conversion. The gas is then sent through a CO_2 absorber, then on to methanation, and then compressed to 4,000 to 4,600 psi (GVC, 2005).

The U.S. produces approximately 13 percent of the global production of anhydrous ammonia. In 2002, 19 companies operated 44 ammonia production plants with a combined capacity of over 15 million metric tons of anhydrous ammonia (TIG, 2002). Over half of the production capacity was centered in Louisiana (10 plants), Oklahoma (5 plants), and Texas (5 plants) due to large reserves of natural gas. Iowa and Kansas have three ammonia plants each; California and Mississippi have two ammonia plants each; and the following states have one ammonia plant each: Alaska, Florida, North Dakota, Wyoming, Oregon, Nebraska, Virginia, Idaho, Alabama, Georgia, Ohio, Tennessee, Illinois and Arkansas. Plants in these states may be good candidates for carbon sequestration projects, because CO_2 is a byproduct of ammonia production.

2.3.1.4 Ethanol Plants

Ethanol is part of an alcohol-based alternative fuel produced by fermenting and distilling starch crops that have been converted into simple sugars. Feedstocks for this fuel include corn, barley, and wheat. Ethanol is most commonly used to increase octane and improve the emissions quality of gasoline. Ethanol can be blended with gasoline to create E85, a blend of 85 percent ethanol and 15 percent gasoline. Vehicles that run on E85 are called flexible fuel vehicles. Looking into the future, the ethanol industry envisions a time when ethanol may be used as a fuel to produce hydrogen for fuel cell vehicle applications.

CO_2 is a main byproduct of the fermentation associated with ethanol production, making ethanol plants good candidates for carbon sequestration projects. According to the Renewable Fuels Association, there are 99 ethanol plants in 19 states within the U.S. that have the capacity to produce nearly 4.9 billion gallons annually. There are also 46 ethanol plants either under new construction or have major expansions under construction with a combined capacity of an additional three billion gallons. Most ethanol plants are located in the Midwest due to the abundant supply of corn and other starch crops. The states with the most ethanol plants are Iowa, Minnesota, South Dakota and Nebraska (see Table 2-6). Ethanol production also occurs in Kansas, Illinois, Indiana, Wisconsin, Colorado, North Dakota, California, Michigan, Missouri, Kentucky, Ohio, Georgia, New Mexico, Tennessee, and Wyoming. Plants are also planned for Texas, Arizona, and Oregon (RFA, 2006).

Table 2-6. Ethanol Producing Facilities in the U.S.

State	Current Facilities	Planned New Facilities or Expansions	Total Current and Future Facilities
Iowa	24	7	31
Nebraska	10	10	20
Minnesota	16	1	17
South Dakota	11	3	14
Kansas	7	2	9
Illinois	6	1	7
Indiana	1	5	6
Wisconsin	5	1	6
Colorado	3	2	5
North Dakota	2	3	5
California	3	1	4
Michigan	1	3	4
Missouri	3	1	4
Texas	0	3	3
Kentucky	2	0	2
Ohio	1	1	2

State	Current Facilities	Planned New Facilities or Expansions	Total Current and Future Facilities
Arizona	0	1	1
Georgia	1	0	1
New Mexico	1	0	1
Oregon	0	1	1
Tennessee	1	0	1
Wyoming	1	0	1
Total	99	46	145

Source: RFA, 2006.

2.3.1.5 Cement Production Facilities

Cement production, while not the largest source of industrial CO_2 emissions, is probably the most intensive source. The Portland Cement Manufacturers Association pledged in February 2003 to adopt a goal of reducing CO_2 emissions per ton of product by 10 percent (from 1990 levels) by the year 2020 (PCA, 2003). Although their plan does not specifically rely on carbon sequestration, it is likely that cement manufacturers would utilize capture/sequestration as a means to meet their reduction goals. The national weighted average carbon intensity (metric tons CO_2 per metric ton of cement produced) was estimated at 0.97 tons CO_2/ton cement in 2001 (Hanle, 2004). The states with the highest total production of cement are (in decreasing order): California, Texas, Pennsylvania, Michigan, Missouri, Alabama, and Florida (see Table 2-7).

Table 2-7. States with the Most Annual Cement Production

State	Millions of Metric Tons
California	11.68
Texas	10.90
Pennsylvania	6.47
Michigan	6.20
Missouri	5.11
Alabama	4.93
Florida	4.80

Note: Data is 2003, except where data was withheld - then the latest year reported was used. Cement production occurs in 37 states, however, USGS data on their website does not reflect mineral production in all 37 states.

Source: USGS, 2003.

2.3.1.6 Sources of Sour Gas (CO_2 with H_2S)

Gas streams consisting primarily of CO_2 with some H_2S can be derived from two primary sources: IGCC power plants and the processing of oil and gas from fields with high H_2S content (sour gas fields).

Currently, there are two IGCC plants producing commercial electricity in the U.S. (in Indiana and Florida), but more of these types of plants are expected to be constructed in the future as clean air regulations promote this low-emission, coal burning technology.

> Sour Gas is defined as natural gas that contains sulfur, sulfur components and/or CO_2 in quantities that may require removal for effective use (because of its corrosive effect on piping and equipment and its danger to human life).

Although comprehensive data is not available on sour gas fields in the U.S., a report conducted by the Gas Research Institute (GRI) in 1991 - using the best available data from the Bureau of Mines at that time - stated that the areas where natural gas had significant levels of H_2S included North Dakota, Wyoming, Texas, Alabama, and Mississippi, with a few exceptionally high concentrations in Texas, Alabama, Mississippi and Florida (GRI, 1991). The report also concluded that approximately 22 percent of the natural gas produced in the continental U.S. contains H_2S at levels exceeding 4 parts per million by volume (ppmv), the pipeline specification for H_2S. Table 2-8 provides a summary of the data presented in the GRI report by state.

Table 2-8. Maximum H_2S Concentrations in Natural Gas

State	Maximum H_2S Concentration in Natural Gas Reported (Percent by Volume)1
Texas	22.80
Alabama	13.80
Mississippi	10.4
Florida	9.50
Michigan	6.50
North Dakota	4.80
Minnesota	2.90
Arkansas	1.85
Wyoming	1.61

[1] *These data were considered incomplete at the time of publication and the authors noted that concentrations provided may under-represent actual values.*

Source: GRI, 1991.

Sour gas injection into deep saline formations and depleted oil or natural gas fields is already occurring at 41 locations in Albert and British Columbia in Canada and at approximately 20 sites in Michigan, New Mexico, Oklahoma, Texas and Wyoming in the U.S (IOGCC, 2005). Therefore, there may be additional sites within these states that would be candidates for co-sequestration of CO_2 and H_2S.

2.3.2 CO_2 Sinks

2.3.2.1 Coal Seams

What constitutes an unmineable coal seam is not clearly defined, and can be further complicated by expected advances in mining technology. Thus, coal seams that run deeper than can be economically mined today may be candidates for mining in the future as technology advances. Consequently, regional applicability is discussed based on the Coal Demonstrated Reserve Base, underground coal data (EIA, 1997). Regions with coal deposits are shown in Chapter 3, Figures 3-15 to 3-17. Data on coal reserves by state is provided in Table 2-9.

Table 2-9. U.S. Coal Demonstrated Reserve Base (1997)

State	Underground Coal (Billion Short Tons)
Illinois	88.1
Montana	71.0
Wyoming	42.5
West Virginia	29.7
Pennsylvania	23.5
Ohio	17.6
Kentucky	17.5
Colorado	11.7
Indiana	8.8
New Mexico	6.2
Alaska	5.4
Utah	5.3
Iowa	1.7

State	Underground Coal (Billion Short Tons)
Missouri	1.5
Washington	1.3
Oklahoma	1.2
Virginia	1.2
Alabama	1.1
North Dakota	0.0
Texas	0.0
Other	1.5
U.S. Total	336.8

Source: EIA, 1997.

Based on these coal reserve data, Illinois and Montana may have the highest potential for coal seam carbon sequestration projects due to their vast underground coal resources. The top ten states with the largest underground coal reserves are (in descending order) are: Illinois, Montana, Wyoming, West Virginia, Pennsylvania, Ohio, Kentucky, Colorado, Indiana and New Mexico.

2.3.2.1.1 Coalbed Methane (CBM)

Carbon sequestration projects are more likely to occur in areas where a primary or secondary economic benefit can be obtained. As CO_2 injection enhances recovery of CBM, CO_2 sequestration projects may be biased towards areas where CBM reserves are known to exist. Conservative estimates suggest that in the U.S. more than 700 trillion cubic feet (Tcf) of CBM exist in place, of which perhaps 100 Tcf are economically recoverable with existing technology, which is the equivalent of about a 5-year supply at present rates of use (USGS, 2001).

The largest known concentration (56 percent) of CBM in the U.S. is in the Rocky Mountains of Wyoming, Utah, New Mexico, Colorado, and Montana. Large deposits of CBM are found and are being developed in the Powder River Basin (northeastern Wyoming and south-central/southeastern Montana), San Juan Basin (northwestern New Mexico), Uinta Basin (northeastern Utah), Piceance Basin (northwestern Colorado), and Raton Basin (southeastern Colorado and northeastern New Mexico). The USGS estimates than approximately 50 Tcf of coalbed methane is extractable in these basins using current technology. Coalbeds that have been strip-mined near the ground surface have lost or "leaked" their coalbed methane over the period of the strip mine activity. Coalbeds that have not been strip-mined, are too deep for strip-mining, or too thinly spaced for surface or underground mining often have recoverable coalbed methane. The Powder River Basin is an excellent example of both: 1) major quantities of coalbed methane recoverable from land proposed for strip mines in the future; and 2) lands with coalbeds thinly present and too deep for economic coal extraction (DOI, 2003). Areas of coalbed methane are shown in Chapter 3, Figure 3-22.

2.3.2.2 Oil and Gas Fields

Oil and gas fields are good candidates for sequestration of CO_2 and also for co-sequestration of H_2S, as both gases aid the recovery of oil and gas, especially when well production drops significantly.

2.3.2.2.1 Potential Locations for Enhanced Oil Recovery (EOR)

Like coal, oil and gas resources are also found in concentrated areas within the U.S. According to the DOE Energy Information Administration U.S. Crude Oil, Natural Gas and Natural Gas Liquid Reserves 2004 Annual Report, 22 percent of the country's proved oil reserves are located in Texas, 20 percent in Alaska, 19 percent in the Gulf of Mexico (Federal offshore), and 16 percent in California (see Table 2-10). Reserves in other states make up the remaining 23 percent (EIA, 2003b). Proved reserves of crude oil declined by 2 percent in 2004 owing mostly to a large 9 percent decrease in the Gulf of Mexico (EIA, 2003b). Although EOR is used for nearly-depleted oil fields, proved oil reserves were used as an indicator for future EOR potential because national data is not collected on depleted oil fields and because currently producing areas will eventually become depleted and may be candidates for EOR in the future.

Table 2-10. Proved Reserves of Crude Oil by State (On-Shore)

State	Million Barrels, 2003
Texas	4,583
Alaska	4,446
California	3,452
New Mexico	677
Oklahoma	588
Wyoming	517
Louisiana	452
North Dakota	353
Montana	315
Kansas	243
Utah	221
Colorado	217
Mississippi	169
Illinois	125
Michigan	75
Florida	68
Ohio	66
Alabama	52
Arkansas	50
Kentucky	25
Indiana	19
Nebraska	16
Pennsylvania	13
West Virginia	13
Other (Includes Arizona, Missouri, Nevada, New York, South Dakota, Tennessee, and Virginia)	16
Total	16,771

Source: EIA, 2003b.

EOR with CO_2 injection was first tried in 1972 in Scurry County, Texas. Since then, CO_2 injection has been used successfully throughout the Permian Basin of West Texas and eastern New Mexico (where about half of all the CO_2 floods in the world are located), as well as in Louisiana, Mississippi, Wyoming, Oklahoma, Colorado, Utah, Montana, Alaska, and Pennsylvania (DOE, 2004). According to a 2002 EOR survey, there were a total of 67 EOR projects in the U.S., 49 of these in the Permian Basin area of West Texas and southeast New Mexico (Moritis, 2002). The Permian Basin is located in West Texas and the adjoining area of southeastern New Mexico. It underlies an area approximately 250 miles wide and 300 miles long and includes the Texas counties of Andrews, Borden, Crane, Dawson, Ector, Gaines, Glasscock, Howard, Loving, Martin, Midland, Pecos, Reeves, Terrell, Upton, Ward, and Winkler. Analyst estimates for the Permian Basin indicate that more than 50 additional projects -adding 500 million to 1 billion barrels of oil reserves- are economically viable at recent prices and current technology. One operator in the Permian Basin planned to initiate 4 to 5 new projects in a 5-year period, in addition to 10 to 12 expansions of existing projects (Moritis, 2001).

DOE is sponsoring a CO_2 injection project (Hall-Gurney Project) into a Lansing-Kansas City formation that was first developed in the 1930s and 1940s. This formation has already been subject to very thorough primary and secondary production. Other possible fields in Kansas that could benefit from CO_2 injection are those that tap the Arbuckle and Morrow Formations of central Kansas.

Additional candidates for CO_2 injection include the Rangely Field in Colorado, the Lost Soldier, Wertz, Salt Creek, Lance Creek, and Mush Creek Fields in Wyoming, numerous other oil fields in Wyoming's Oregon and Elk Basins, and the Bell Creek Field in Montana (Goerold, 2002).

In Mississippi, the Jackson Dome CO_2 source is being used for EOR recovery in the Little Creek field. The operator of the Little Creek field claimed in 2001, "…as much as 1 billion barrels of incremental oil might be recovered through the use of CO_2 flooding"(OGJ, 2001).

Yet another prominent example of CO_2 oil recovery is seen in the San Joaquin Basin of California. Because of poor formation characteristics such as poor permeability, poorly-developed fractures, and a complex geology, oil fields in this southern California basin have produced only about 6.5 percent of the oil, out of an estimated 2.6 billion barrels of oil in place (OGJ, 2000).

DOE has concluded that CO_2 EOR can be utilized to recover "stranded" resources that have been or will be left behind after the use of traditional oil recovery methods. As shown in Table 2-11, EOR could be used to recover nearly 89 billion barrels of oil in assessed oil reserves in many regions of the country, which would be left behind if only traditional recovery methods were used.

Table 2-11. CO_2 EOR Technically Recoverable Resource Potential

Basin/Area	Number of Large Formations Assessed	All Formations (Ten Basins/Areas assessed)		
		Original Oil in Place (billion barrels)	Remaining Oil in Place (billion barrels)	Technically Recoverable (billion barrels)
Alaska	34	67.3	45.0	12.4
California	172	83.3	57.3	5.2
Gulf Coast	239	44.4	27.5	6.9
Mid-Continent	222	89.6	65.6	11.8
Illinois and Michigan	154	17.8	11.5	1.5
Permian (West Texas and New Mexico)	207	95.4	61.7	20.8
Rocky Mountains	162	33.6	22.6	4.2
Texas (east and central)	199	109.0	73.6	17.3
Williston	93	13.2	9.4	2.7
Louisiana Offshore	99	28.1	15.7	5.9
Total	1,581	581.7	390.0	88.7

2.3.2.2.2 Potential Locations for Sequestration in Natural Gas Formations

CO_2 can also be sequestered in depleted natural gas fields. The largest natural gas fields in the U.S. are in Texas, Wyoming, Oklahoma, New Mexico, Louisiana, and Colorado (see Table 2-12). Total U.S natural gas withdrawal in 200 was over 14 trillion c.f. Due to the vast natural gas fields in these states, they may contain the best potential natural gas field sites for carbon sequestration projects. Other states producing natural gas (greater than 10 billion cubic feet a year) are: Kansas, Alabama, Utah, Alaska, Michigan, West Virginia, Pennsylvania, Arkansas, Mississippi, California, Ohio, Kentucky, Virginia, Montana, New York, and North Dakota (EIA, 2005a). These states also have potential for future carbon sequestration projects.

Table 2-12. Natural Gas Withdrawals from Gas Wells, 2003

State	Natural Gas Withdrawals (Million Cubic Feet)
Texas	4,947,589
Wyoming	1,652,504
Oklahoma	1,487,451
New Mexico	1,391,916
Louisiana	1,283,513

State	Natural Gas Withdrawals (Million Cubic Feet)
Colorado	970,229
Kansas	369,624
Alabama	365,330
Utah	254,488
Alaska	196,989
Michigan	194,121
West Virginia	187,723
Pennsylvania	159,827
Arkansas	157,039
Mississippi	156,727
California	90,368
Ohio	87,993
Kentucky	87,608
Virginia	81,086
Montana	78,175
New York	35,943
North Dakota	14,524
Indiana	1,464
Nebraska	1,187
Oregon	731
South Dakota	550
Arizona	443
Illinois	169
Maryland	48

Source: EIA, 2005a.

2.3.2.2.3 Saline Formations

Saline formations are good sinks for CO_2 and also for co-sequestration of CO_2 and H_2S. One of the goals of DOE's Carbon Sequestration Program is to continue to assess potential saline formations that are suitable for sequestering CO_2.

In a 2003 study funded by DOE/NETL, the Bureau of Economic Geology (BEG) at the University of Texas at Austin inventoried 16 geologic characteristics of 21 brine-bearing formations in the continental U.S. to provide basic data needed to assess the feasibility, costs, and risks of this sequestration method (BEG, 2003). These 21 formations covered an area of 4.3 million square kilometers (1.66 million square miles) or roughly 56 percent of the contiguous U.S.. While BEG acknowledged that many other formations may be suitable for field studies at a pilot scale or for sequestering output of individual emitters, their study focused on formations with the potential to scale up to store large volumes of CO_2.

BEG selected only one formation as a target in most areas, so the results are not comprehensive, nor should they be considered a capacity assessment. The study did however characterize many of the major, regionally extensive saline formations to improve the chance of matching as many sites as possible. One of the most favorable units that BEG assessed is the Frio Formation of the Gulf Cost, with 300 m of sand over wide areas and 28 to 35 percent porosity.

A map of deep saline formations within the U.S. is provided in Chapter 3, Figure 3-24. Additionally, saline formations undergoing study by the Regional Partnerships are presented in Figure 3-25. The data from this map is comprised of GIS data from the individual Regional Partnerships. Some Partnerships are still developing their GIS database and therefore saline formations in some regions are not fully represented by this figure.

2.3.2.3 Basalt Formations

Another option for geologic sequestration is basalt formations. Basalt is a hard, black volcanic rock and is the most common rock type in the Earth's crust (outer 10 to 50 kilometers). Most of the ocean floor is made of basalt. Large areas of lava called "flood basalts" are found on many continents. For example, the Columbia River basalts erupted 15 to 17 million years ago and cover most of southeastern Washington and regions of Oregon and Idaho (USGS, 2005).

Major basalt formation may be attractive for carbon sequestration in the Pacific Northwest, the Midwest, the Southeastern U.S. and several other locations. Basalt formations have unique properties that can chemically trap injected CO_2, effectively and permanently isolating it from the atmosphere (NETL, 2004).

"Preliminary experiments conducted at Pacific Northwest National Laboratory (PNNL) have confirmed that carbonate mineral formation occurs when basalts from the Columbia River Basalt Group are exposed to supercritical CO_2" (NETL, 2004).

Basalt formations that hold the most promise for carbon sequestration are: Columbia River Basalt Group; Snake River Plain; Keweenawan Rift Basalts; East Continental Rift Zone; Newark Supergroup; Northern California Volcanics; Southern Nevada Volcanics; and Southeast Rift Zone (Figure 3-26).

2.3.2.4 Terrestrial Sequestration

Under DOE's Carbon Sequestration Program, future terrestrial sequestration projects may focus on reclamation and restoration of mined lands and other properties that have been degraded as a consequence of mineral extraction for energy development. Therefore, areas targeted primarily under DOE's Carbon Sequestration Program will consist of former surface mining sites.

The Rural Abandoned Mine Program (RAMP) was authorized by Section 406 of the Surface Mining Control and Reclamation Act (SMCRA) of 1977 as amended by the "Abandoned Mine Reclamation Act of 1991" as subtitled under the Budget Reconciliation Act (Public Law 101-508; 30 U.S.C. 1236). It is authorized for the purpose of reclaiming the soil and water resources of rural lands adversely affected by past coal mining practices. There were approximately 1.1 million acres of abandoned coal-mined land needing reclamation in 1977 (NRCS, 2005).

> Under DOE's Program, terrestrial sequestration projects will focus on reclamation and restoration of formerly mined lands and other properties that have been degraded as a consequence of mineral extraction for energy development.

The total magnitude of the abandoned mine problem is difficult to assess, but OSMRE (Office of Surface Mining Reclamation and Enforcement) has developed a national inventory that contains information on more than 17,700 problem areas associated with abandoned mine lands, mostly coal. A problem area is a geographical area, such as a watershed, that contains one or more problems. The more serious problem areas are classified as priority 1 (extreme danger to public health and safety), priority 2 (adverse affects to public health, safety, and general welfare), or priority 3 (environmental hazards). Since 1977, over 190,000 equivalent acres of priority 1 and 2 health and safety, and environmental-related coal problems have been reclaimed (OSMRE, 2005a).

Querying the OSMRE Abandoned Mine Land Inventory System (AMLIS) for priorities 1, 2, and 3 problem areas, a list of the number of acres or acre-equivalents of land to be restored in each state was generated (OSMRE, 2005b). The results of this query are provided in Table 2-13. Based on these data, the U.S. has an estimated 13,581,700 acres of land designated priority 1, 2, or 3. Using these results, states that may have the most acres available for reforestation or terrestrial sequestration projects on previously mined lands include West Virginia, Virginia, Alabama, Pennsylvania and Oklahoma. This list is not considered a definitive list of available acres that could be reforested, but may be useful as an indicator as to which states may have the most potential for future terrestrial sequestration projects under DOE's program.

Table 2-13. Abandoned Mine Land Problem Areas

State	Abandoned Mine Land Problem Areas (Acres or Acre-Equivalents, Priority 1, 2, 3)
West Virginia	4,997,570
Virginia	2,208,110
Alabama	2,180,250
Pennsylvania	1,687,630
Oklahoma	1,001,830
Missouri	248,200
Kansas	220,380
Ohio	165,190
Kentucky	142,540
Illinois	133,470
Maryland	126,580
Iowa	119,810
North Dakota	112,230
Tennessee	99,660
Arkansas	73,410
Washington	16,000
Alaska	12,870
Indiana	12,840
Wyoming	10,000
Colorado	5,900
Utah	5,800
Georgia	1,430

Source: OSMRE, 2005b.

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2.4 REGIONAL APPLICABILITY

The degree of implementation of carbon sequestration technologies within the U.S. will be influenced by a variety of factors. These factors include availability and proximity of land and geologic resources that provide sinks for CO_2, the number of CO_2 point-sources, air quality regulations and incentive programs at the state and federal level, and the degree to which funding is available.

> Availability of CO_2 from point sources is not expected to be a limiting factor in carbon sequestration technology deployment. Rather, deployment would be influenced to a greater degree by the presence of suitable geologic resources or, in the case of terrestrial sequestration, availability of appropriate land.

Although the types and quantities of point source CO_2 could influence commercial deployment rates of sequestration technologies, availability of CO_2 is not expected to be a limiting factor in technology deployment. Rather, future carbon sequestration deployment would be influenced to a greater degree by the presence of suitable geologic resources or, in the case of terrestrial sequestration, availability of appropriate land. In the case of co-sequestration, sources of CO_2/H_2S gas streams would consist primarily of waste streams from IGCC plants, or sour gas oil and gas processing plants. As there are only 2 commercial IGCC plants in the nation, the presence of sour gas from oil and gas processing in each state has been used as an indicator as to future potential for co-sequestration technology in each region.

As in Section 2.3, various indicators have been chosen to provide some relative measure of the applicability of different sequestration technologies within each state. While carbon sequestration R&D projects can occur in most regions due to their relatively limited size and scope, future commercialization will be influenced to a greater degree by the availability of suitable sinks.

2.4.1 Resources in the States

A summary of carbon sequestration technology applicability indicators for each state is provided in Table 2-14.

Overall, the U.S. has vast coal resources that can be utilized for carbon sequestration. As illustrated in Table 2-14, the states with the greatest demonstrated coal reserves include Illinois (88.1 billion short tons), Montana (71.0 billion short tons), Wyoming (42.5 billion short tons), West Virginia (29.7 billion short tons), and Pennsylvania (23.5 billion short tons). Ohio, Kentucky, and Colorado each have substantial reserves with 17.6, 17.5, and 11.7 billion short tons of demonstrated coal reserves respectively. To a lesser degree Indiana, New Mexico, Alaska, and Utah have meaningful coal reserves at 8.8, 6.2, 5.4, and 5.3 billion short tons respectively. Several states have minimal demonstrated resources with less than 2 billion short tons, which include Alabama, Missouri, Oklahoma, Virginia, and Washington. The remaining states have no demonstrated coal reserves.

The U.S. has significant crude oil resources that could be utilized for carbon sequestration through enhanced oil recovery, which are primarily found in the western half of the country. The states with by far the greatest oil reserves are Texas (4,583 million barrels), Alaska (4,446 million barrels), and California (4,251 million barrels). Several states have no oil reserves, which include Georgia, Idaho, Iowa, Maryland, Minnesota, North Carolina, Oregon, South Carolina, Washington, and Wisconsin. The remaining states contribute between 1 and 667 million barrels (see Table 2-14 for details).

The U.S. has considerable potential to utilize depleted natural gas reserves for carbon sequestration, which is evidenced by natural gas production totals. Texas is by far the greatest natural gas producer in the country with 4.9 trillion cubic feet produced a year.

There are many opportunities for saline formation sequestration throughout the vast majority of states. In southeastern Illinois and southwestern Indiana, below oil formations, is a major saline formation, the Mt. Simon Sandstone, which is widely present at depths from 6,000 to 13,000 feet. The geology of the Mt. Simon formation makes it an excellent storage unit and the caprock seal of the Eau Claire Shale has proven its performance as a seal in containing natural gas (Finley et al., 2004). This formation is generally heterogeneous, which will increase the need for detailed formation characterization and the careful placement of CO_2 in this saline formation. The Madison Group, Williston Basin is an elliptical-shaped basin that extends from the northern Great Plains of the U.S. into Canada. The basin occupies most of North Dakota, northwestern South Dakota, eastern Montana, and a part of southern Manitoba and Saskatchewan in Canada. The U.S. part of the basin presents a maximum Phanerozoic thickness of 16,000 ft in North Dakota.

Carbon sequestration projects in basalt formations could be sited in many locales within the U.S. Portions of the Newark Supergroup basalts underlie parts of Pennsylvania, Maryland and Virginia. The East Continent Rift Zone basalts underlie parts of Ohio, Indiana, and Kentucky. The Keweenawan Rift basalts underlie portions of Michigan, north-central Kansas, northern Wisconsin, eastern and southern Minnesota, central Iowa, and eastern Nebraska. Illinois, Indiana, and Kentucky, central Tennessee, and northern Alabama each contain a portion of the East Continental Rift Zone basalts. The Southeast Rift Zone basalts are found within parts of South Carolina, Georgia, northwestern Florida and southeastern Alabama. The Southern Nevada Volcanics underlies parts of Nevada and the Northern California Volcanics underlies parts of California. Two of the most promising basalt formations for carbon sequestration, the Columbia River Basalt Group and the Snake River Plains, underlie parts of the northwest.

Table 2-14. Technology Applicability Indicators and Results for the States

State	Coal Seam Sequestration [Coal Demonstrated Reserve Base, (billion short tons)]	Oil and Gas Reserve Sequestration Indicators		Saline Formation Indicator [Are Suitable Saline Formations Present?]	Basalt Formation Indicator [Are Notable Basalt Formations Present?]	Terrestrial Sequestration Indicator [Abandoned Coal Mine Acres or Acre-Equivalents]	Co-Sequestration Indicator [Is Sour Gas Known to be Present?]
		Enhanced Oil Recovery [Crude Oil Reserves, (millions of barrels)]	Depleted Natural Gas Formations [Natural Gas Production (million c.f./year)]				
Alabama	1.1	52	365,330	yes	Yes	2,180,250	yes
Alaska	5.4	4,446	196,989	Yes		12,870	---
Arizona	--	*	443	Yes	No	---	---
Arkansas	--	50	157,039	Unknown	No	73,410	---
California	--	4,251	90,368	Yes	Yes	---	---
Colorado	11.7	217	970,229	Yes	No	5,900	---
Florida	--	68	0	yes	Yes	---	---
Georgia	--	0	0	yes	Yes	1,430	---
Idaho	--	0	0	No	Yes	---	---
Illinois	88.1	125	169	Yes	Yes	133,470	---
Indiana	8.8	19	1,464	Yes	Yes	---	---
Iowa	0	0	0	Yes	Yes	119,810	---
Kansas	0	243	369,624	Yes	Yes	220,380	---
Kentucky	17.5	25	87,608	Yes	Yes	142,540	---
Louisiana	--	452	1,283,513	yes	No	---	---
Maryland	--	0	48	Yes	Yes	125,580	---
Michigan	--	75	194,121	Yes	Yes	0	yes
Minnesota	0	0	0	Yes	Yes	---	yes
Mississippi	--	169	156,727	yes	No	---	yes
Missouri	1.5	*	0	Yes	No	248,200	---
Montana	71.0	315	78,175	Yes	No	---	---
Nebraska	0	16	1,187	Yes	Yes	---	---
Nevada	--	*	0	Yes	Yes	---	---

State	Coal Seam Sequestration [Coal Demonstrated Reserve Base, (billion short tons)]	Oil and Gas Reserve Sequestration Indicators		Saline Formation Indicator [Are Suitable Saline Formations Present?]	Basalt Formation Indicator [Are Notable Basalt Formations Present?]	Terrestrial Sequestration Indicator [Abandoned Coal Mine Acres or Acre-Equivalents]	Co-Sequestration Indicator [Is Sour Gas Known to be Present?]
		Enhanced Oil Recovery [Crude Oil Reserves, (millions of barrels)]	Depleted Natural Gas Formations [Natural Gas Production (million c.f./year)]				
New Mexico	6.2	667	1,391,916	Yes	No	---	yes
North Carolina	--	0	0	yes	No	---	---
North Dakota	0	353	14,254	Yes	No	112,230	yes
Ohio	17.6	66	87,993	Yes	Yes	165,190	---
Oklahoma	1.2	588	1,487,451	Yes	No	1,001,830	yes
Oregon	--	0	731	Yes	Yes	---	---
Pennsylvania	23.5	13	159,827	Yes	Yes	1,687,630	---
South Carolina	--	0	0	yes	Yes	---	---
South Dakota	--	*	550	Yes	No	---	---
Tennessee	--	*	0	yes	Yes	---	---
Texas	--	4,583	4,947,589	yes	No	---	yes
Utah	5.3	221	254,488	Yes	No	5,800	---
Virginia	1.2	*	81,086	yes	Yes	2,208,250	---
Washington	1.3	0	0	Yes	Yes	16,000	---
West Virginia	29.7	13	187,723	Yes	No	4,997,570	---
Wisconsin	0	0	0	Yes	Yes	---	---
Wyoming	42.5	517	1,652,504	Yes	Yes	10,000	yes

There are ample opportunities for terrestrial sequestration projects on lands containing abandoned coal mines. DOE's Carbon Sequestration Program would focus on terrestrial sequestration projects on formerly coal-mined lands; therefore, states with the greatest amounts of these land cover types would provide the largest amount of land for DOE-sponsored projects. West Virginia has by far the greatest amount of formerly coal-mined lands with nearly 5 million acres. Alabama and Virginia each have approximately 2.2 million acres of these lands. Pennsylvania has about 1.7 million acres and Oklahoma has about 1 million acres. Missouri has over 248,000 acres and Kansas has more than 220,000 acres. Illinois, Iowa, Kentucky, Maryland, North Dakota, and Ohio each contain between 112,000 and 166,000 acres of formerly coal-mined lands. Alaska, Arkansas, Colorado, Georgia, Utah, Washington, and Wyoming each contain between 1,400 and 73,500 acres.

States with natural gas reserves with elevated levels of H_2S (sour gas) could be locations for co-sequestration projects. Sour gas is known to be present in Alabama, Michigan, Minnesota, Mississippi, New Mexico, North Dakota, Oklahoma, Texas, and Wyoming.

2.4.2 Future Commercial Deployment of Carbon Sequestration Technologies

Based on these data by states presented in Section 2.4.1, regional differences can be expected in the levels of future commercial deployment of each technology. Table 2-15 summarizes estimated future deployment levels for each carbon sequestration technology. The levels indicate high, medium, or low opportunity of commercial deployment for each technology based on their geologic features and

> Estimated levels of future commercial deployment for each Regional Partnership reflect each region's geologic features and resources, relative to other regions in the U.S.

resources, and are meant to provide a general comparison of resources.

The levels should be evaluated in the context of each technology. For example, if a region shows a high deployment level for basalt sequestration, this only means it is high relative to other regions across the U.S. It does not necessarily mean that there are more opportunities for basalt sequestration than other types of sequestration within that region.

The estimated deployment levels are provided to assist in the broad understanding the overall potential for future commercial deployment of technologies in these areas and are not indicators relating to the Program's planned level of regional funding or sponsorship of future research activities.

While some geologic formations have been characterized for their suitability for carbon sequestration, much more research still needs to be done to identify and characterize other potentially suitable formations. Therefore, overall, these estimated deployment levels do not reflect results of specific characterizations of geologic formations in these regions. A discussion of the types of investigations typically conducted and the general characteristics of suitable geologic formations is provided in Section 2.4.3.

Table 2-15. Estimated Future Commercial Deployment Levels

Regional Partnership	Coal Seam Sequestration (including ECBM)	Oil and Gas Formations (including EOR)	Sequestration in Saline Formations	Sequestration in Basalt Formations	Terrestrial Sequestration[1]	Co-Sequestration of CO2 and H2S
Midwest	High	Low	High	Medium	High	Medium
Illinois Basin	High	Low	High	Medium	Low	Low
SECARB	Low	High	High	High	High	High
Southwest	Medium	High	High	Low	Medium	High
West Coast	Low	High	High	High	Low	Low
Big Sky	High	Medium	High	High	Low	Low
PCOR	High	Medium	High	Medium	Low	High

[1] Deployment level is based on acreage of abandoned coal mine areas only. Other large areas of land may be suitable for terrestrial sequestration within each Regional Partnership.

2.4.3 Determining Suitable Sinks

A suitable sink for geologic sequestration purposes is an effective formation system, which is generally considered to be highly porous (i.e., with large pore spaces, or void fractions), and highly permeable (i.e., with low resistance to fluid flow within the formation), and overlain by a thick seal. Such a system promotes ease of CO_2 injection, minimization of pressure effects, and high pore space storage capacity. A thick seal is necessary to prevent leakage of CO_2 to overlying formations. While effective injectivity and sufficient storage capacity are important for CO_2 storage, containment is a critical aspect for any storage site to be successful, and to be considered a sink suitable for long-term storage of sequestered CO_2 (Watson and Gibson-Poole, 2005).

Because of the economic value associated with oil and gas formations and coal seams, much formation information is available for those geologic sequestration applications. However, little physical data exist for many saline formations, especially at depths greater than 2500 feet (Myer et al., 2005).

Sinks suitable for geologic sequestration exhibit the following mechanisms for CO_2 storage (NETL, 2005):

- **Caprock trapping**. An impermeable layer of low-porosity rock serves as a barrier against upward migration of CO_2.
- **Pore space trapping**. Through capillary and surface tension forces, droplets of CO_2 become affixed into a rock pore space (primarily for oil and gas formations, and also for saline formations to some extent).
- **Solubility trapping**. Dissolution of CO_2 in saline water, as CO_2 is soluble in brine. For example, at 1900 psi and 30,000 ppm TDS, one gallon of brine holds 0.4 pounds of CO_2 (primarily for saline formations and basalt formations, and also for oil and gas formations to some extent).
- **Mineralization**. Once in solution, CO_2 will react, albeit at a slow rate, with dissolved minerals to form solid mineral carbonates (primarily for high magnesium content basalts, and for saline formations).
- **Adsorption**. Unmineable coal seams offer a unique storage mechanism as CO_2 molecules adsorb onto the surface of the coal. Adsorbed CO_2 exists as a condensed liquid and is immobile so long as the formation pressure is maintained.

One research group characterized coal at depths greater than 1200 feet as being unmineable. At those depths, a minimum coal seam thickness of 1.5 feet was selected for purposes of identification, accommodating perforations, and production from the coal seam. High permeabilities of 50 mD have been an indicator for potential enhanced coal bed methane (ECBM) recovery. CO_2 storage factors for coal seams (i.e., CO_2 versus methane original gas in place [OGIP], and as a fraction of total storage capacity) generally increase with depth. Sequestration opportunities are also classified at depths of 900-1200 feet (with 500-600 psi formation pressures, and permeabilities of 5-20mD); however, at these shallower depths, coal seam thicknesses would need to be less than 3.5 feet, as thicker seams are likely to be mineable. Finally, at depths of less than 500 feet, no sequestration opportunities are indicated at these shallower depths (Anderson et al., 2005). As CO_2 becomes a super-critical fluid at approximately temperatures greater than 90^{o}F and pressures greater than 1100 psi, there is a lower leakage potential at greater depths (and pressures), as CO_2 stays out of the gaseous phase and is less mobile, and there are less fractures in the coal seam from past mining activities (Drobniak et al., 2005).

For EOR CO_2 sequestration opportunities, the following formation parameters are key in determining the suitability of potential sinks (Knepp, et. al., 2005 and Smith, et. al., 2005):

- Depth
- Field area
- Producing interval thickness
- Miscibility (CO_2 dissolved in oil, or in a separate phase) condition
- Depth to miscible/immiscible boundary (as a function of pressure and temperature gradients)
- Original oil in place (OOIP; a function of formation drainage area, thickness, and porosity)
- Saturation of oil/initial formation water saturation
- Porosity and permeability
- Oil viscosity and API gravity (oil density)
- Recovery and storage factors

In one field evaluated, the formation was typically less than 10 feet thick, and was ¼ mile wide and 2 miles long. Based on available well data and formation modeling, it was estimated that an additional 10-15 percent of oil production could be achieved over 25 years using CO_2 injection (above the production that could be achieved from primary recovery and secondary water flooding) (Knepp et al., 2005).

Suitable saline formations would be located at depths similar to suitable coal seams. The following are key parameters for saline formations as potentially suitable sinks for CO_2 storage (Smith et al., 2005):

- Salinity
- CO_2 solubility
- Porosity and permeability
- Thickness
- Area

As discussed previously, the presence of an effective caprock is a critical component to ensuring the successful long-term storage of CO_2. Some of the key caprock properties that help determine the suitability of a potential CO_2 sink include (Statoil, 2005 and Myer et al., 2005):

- Trap type – structural and/or stratigraphic
- Seal thickness
- Permeability
- Capillary entry pressure

Characterization of a formation to determine its potential suitability for long-term CO_2 storage is a relatively complex undertaking. Such a characterization is intended to determine its structure, stratigraphy, and physical properties. It must include an analysis of seismic and borehole data, augmented by rock material (core and cuttings). This formation mapping should include at a minimum:

- Depth to top formation
- Formation thickness
- Formation physical properties (see below)
- Lateral and vertical stratigraphical and hydraulic continuity
- Regular grid of 2D seismic data over entire formation
- High quality 3D seismic volume over the potential injection site and adjacent area
- Borehole data to permit accurate depth conversion of seismic data
- Such geophysical log data should be collected from wells at least as far from the potential injection point as the predicted CO_2 migration within the formation (Statoil, 2005).

Key formation physical properties to be determined in such a characterization include (Statoil, 2005 and Myer et al., 2005):

- Area
- Thickness
- Porosity and permeability
- Rock particle size distribution
- Sand/shale ratio (if applicable)
- Formation fluid
- Initial pressure and temperature
- Formation water salinity
- Pore water analysis/formation-water-CO_2 chemical reactions
- Formation temperature and allowable injection pressure (determine CO_2 density)

2.5 REPRESENTATIVE MODEL PROJECTS, CHARACTERISTICS AND ENVIRONMENTAL ISSUES

2.5.1 Introduction

As indicated previously in Section 2.1, several model projects were defined and analyzed to determine potential environmental impacts of implementing the Carbon Sequestration Program's technologies. Model projects were developed only for those Carbon Sequestration Program technologies that are likely to be deployed by DOE or others at a much larger, commercial-scale within the next 10 years. The technologies for which model projects were developed include the following:

- Post-combustion CO_2 Capture
- CO_2 Compression and Transport
- Coal Seam Sequestration
- Enhanced Oil Recovery Sequestration
- Saline Formation Sequestration
- Basalt Formation Geologic Sequestration
- Reforestation of Mined Lands
- Co-sequestration of CO_2 and H_2S

For each of these model projects, the following elements of the technology's field application were characterized:

<u>General design and operating parameters</u>

- Process flow diagram
- Type, size, and number of major equipment items
- CO_2 captured, transported, or sequestered
- Monitoring, mitigation, and verification (MM&V) approach
- Utility requirements
- Electricity
- Water
- Steam
- Fuel

<u>Environmental process discharge streams</u>

- Air emissions
- Wastewater
- Solid and liquid wastes
- Drilling cuttings

<u>Site requirements and operations</u>

- Land requirements (total and disturbed)
- Access roads
- Pipelines
- Chemical requirements

- Personnel
- Duration

Construction phase activities

- Site clearing
- Construction
- Duration
- Personnel

Detailed model project descriptions are presented in Sections 2.5.3-2.5.10. Summary tables of Model Project environmental parameters are provided in Section 2.5.11.

Detailed model projects were not developed for those DOE-NETL Carbon Sequestration Program technologies that are in their early stages of development. Carbon sequestration technologies that were not considered further include those that are:

- not likely to be deployed at a pilot or commercial scale within the next ten years;
- currently in an experimental stage where detailed process information is currently unavailable; or
- under the primary purview of another Federal agency (e.g., agriculture terrestrial sequestration programs by U.S. Department of Agriculture).

In lieu of detailed model projects, brief technology descriptions of DOE-NETL's R&D activities are presented Appendix B for the following technologies:

- Pre-combustion Decarbonization and Oxyfuel Combustion
- Other Geologic Formations
- Shale
- Mineralization (e.g., serpentine)
- Agricultural Terrestrial Sequestration
- Ocean Sequestration (which is no longer investigated by the Program)
- Co-sequestration of CO_2 and SO_2/NO_X

2.5.2 Existing Geologic Sequestration Projects – Injection Data

There are over 70 commercial-scale CO_2 EOR projects operating in the U.S., with several having experienced CO_2 injection for periods of 20-30 years. CO_2 injection into saline formations has been performed at a commercial scale in three large projects worldwide, with a fourth due to commence operation in the 2006-2008 timeframe (with several of these projects injecting CO_2 under the seabed). Several small, pilot saline formation CO_2 injection projects have also been performed. Coal seam/ECBM applications have only had two large, multi-well pilot demonstrations, with the few other projects being single well, "micro-pilot" tests. Finally, there have been no basalt formation field tests conducted to date in the U.S., with the first pilot validation test planned as part of the Regional Partnerships Phase II testing.

Table 2-16 summarizes the rates of CO_2 injection and number of injection wells for many of the larger CO_2 geologic sequestration projects that have been conducted throughout the world. For comparative purposes, several of the largest commercial CO_2 EOR projects and the small saline formation pilot projects have also been included. Much less information is readily available on the number of monitoring wells, but it is included in the table where identified.

For the four EOR projects shown in Table 2-16, the annual CO_2 injection rates range from approximately 1.5 to 10 million tons CO_2 per year. Maximum daily injection rates ranged from about

4,000 to 28,000 tons CO_2 per day. As the number of CO_2 injection wells range from 57 to 365, CO_2 injection rates of 54 to 75 tons per day per injection well are estimated. Given the extensive commercial experience associated with the CO_2 EOR technology and the desire to minimize environmental and economic impacts associated with drilling new wells, the model project for EOR assumes an average CO_2 injection rate of 75 tons per day per injection well. For a model project nominally sized at injecting a total of 1 million tons CO_2 per year, this results in a maximum value of 36 injection wells. This is the number of CO_2 injection wells used in the EOR geologic sequestration model project in Section 2.5.6.

For the four commercial scale saline formation projects shown in Table 2-16, annual CO_2 injection rates are on the order of about 1 to 3 million tons CO_2 per year. Maximum daily injection rates are approximately 3,000 to 10,000 tons CO_2 per day. With the number of CO_2 injection wells varying from 1 to 7, this results in CO_2 injectivities of approximately 1,400 to 3,700 tons per day per injection well. These values (being roughly 30 to 50 times that of EOR applications) reflect, in part, the extremely high permeability and porosity associated with saline formations compared to oil formations. Because these projects often involve injecting into deeper formations (to inject below all commercial mineral leases and to avoid any underground sources of drinking water), the costs of drilling and operations and maintenance is much greater. Therefore, in the commercial projects to date, which have been all outside the U.S., there have been several reasons to maximize the CO_2 injectivity of each well.

The saline formation model project assumes a maximum number of 7 injection wells (based on the Gorgon project), injecting a nominal total of about 1 million tons CO_2 per year (based on an average of Sleipner and Snohvit). For the minimum, the model project assumes 1 injection well based on the Frio and Nagaoka pilot projects (See Section 2.5.7).

Table 2-16. Geologic Carbon Sequestration Project CO_2 Injection Rates and Wells

Technology Type	Project	CO_2 Injection Annual, tpy	CO_2 Injection Max, tpd	Number of Injection Wells	CO_2 Injection, tpd/well	References
EOR	Weyburn	1,700,000	5,500	85	65	*O&GJ-2004, PTRC-2005*
EOR	Rangely Weber	3,300,000	11,300	209	54	*Stevens-2000, O&GJ-2004*
EOR	SACROC	1,400,000	3,700	57	64	*EPRI-1999, O&GJ-2004*
EOR	Wasson Denver	10,000,000	27,500	365	75	*EPRI-1999, O&GJ-2004*
Saline (On land and sub-seabed)	Gorgon	3,300,000	9,600	7	1,380	*Chevron-2005*
Saline (Sub-seabed)	Sleipner	1,100,000	3,700	1	3,700	*Statoil-2002*
Saline/EGR	In Salah	1,300,000	4,300	3	1,430	*Riddiford-2004*
Saline (Sub-seabed)	Snohvit	800,000	2,900	1	2,900	*Maldal-2004*
Saline	Nagaoka	11,000	44	1	44	*Kikuta-2004*
Saline	Frio	3,000	140	1	140	*Hovorka-2004, Hovorka-2001*
Coal ECBM	Allison	N.A.	183	4	46	*White-2005*
Coal ECBM	Consol	6,700	18	1	18	*NETL-2002*
Coal ECBM	RECOPOL	1,100	17	1	17	NITG-2005

As mentioned previously, all the coal ECBM projects have either been pilot tests or single well “micro-pilot” tests. Based on these tests, CO_2 injectivity ranged from approximately 17 to 46 tons per day per injection well. For purposes of the coal seam ECBM model project, the maximum number of wells for a commercial-scale project is based on the Allison project’s average injection rate of 46 tons per day per well. This results in a maximum of 60 CO_2 injection wells (See Section 2.5.5). The minimum number is assumed to be a single injection well pilot (based on Consol and RECOPOL).

A limited review of literature regarding formation CO_2 injectivity was conducted to formulate the model projects for coal seams, EOR, saline formations, and basalt formations. Table 2-17 summarizes the results on porosity and permeability values based on that review.

Table 2-17. Representative Formation Porosities and Permeabilities

Formation/ Formation Type	Porosity, % (Max)	Permeability, mD	References
Coal Seam/ ECBM	<1 - 2	1 – 100	ARI-2003, Bromhal-2004, Reeves-2003, Srivistava-2005, Wolf-2000.
Oil Formation/ EOR	10 - 25	5 – 1000	Knepp-2005, O&GJ-2004, Smith-2005, Stevens-2000, Westrich-2002.
Saline Formation	20 - 40	200 – 3000+	Audigane-2005, Hovorka-2004/2001, Kikuta-2004, Leetaru-2005, Myer-2005, NETL-2003, Saripalli-2005.
Basalt Formation	5 – 40+	1 – 1000+	Kumar-2005, Matter-2005, McGrail-2005a/b, McGrail-2003, O’Connor-2001, Reidel-2002, Saar-1999.

Coal seams contain more water and methane gas and are typically located at shallower depths than oil or saline formations. This significantly reduces the available porosity and limits the CO_2 injectivity, with injectivity being a function of permeability and injection area. Because of the relatively low permeability and porosity of coal seams, along with the tendency for the coal cleats to swell with CO_2 adsorption, more complex well drilling patterns (horizontal wells) and/or fracturing methods may be necessary. Therefore, coal seam/ECBM technologies will tend to have a greater number of injection wells (with tighter spacing) than the other geologic sequestration technologies.

For coal seam ECBM CO_2 injection well spacing, typical well spacings are on the order of 40, 160, or 320 acres (White, 2005). Based on some of the CO_2 injectivity problems experienced with several of the pilot field tests, the model project assumes a 40-acre spacing per CO_2 injection well for the coal seam model project (see Section 2.5.5).

For EOR geologic sequestration applications, a review of the approximately 70 U.S. CO_2 miscible EOR projects was performed. Evaluating the middle 80 percentile of the population of CO_2 EOR fields produced values for field acreage to numbers of CO_2 injection wells ranging from about 30 to 220 acres/injection well, with an average of approximately 74 acres per injection well (O&GJ, 2004). This value was used in the CO_2 EOR geologic sequestration model project to determine the maximum acreage potentially affected by a commercial scale project (see Section 2.5.6). Given the significantly higher permeability of oil formations when compared to coal seams, the EOR CO_2 injection well spacing used in the model project for EOR is almost twice that of the coal seam ECBM model project.

Saline formations show much higher porosities and permeabilities than do oil formations, with basalt formations potentially approaching the injectivity of saline formations, as shown in Table 2-17. For potential well spacing for saline formation applications, a review of the world’s largest saline formation CO_2 injection project was performed. Based on the formation modeling studies performed of the stratigraphic and hydrogeologic characteristics of the Dupuy formation, the CO_2 injection wells for the Gorgon project are separated by approximately 2 kilometers by 4 kilometers (6,600 ft by 13,200 ft) grid spacing (Chevron, 2005). These values will be used to estimate CO_2 injection well spacing and total acreage affected for the saline formation geologic sequestration model project (see Section 2.5.7).

For the basalt formation geologic sequestration model project, where adequate data are not available, it is assumed that basalt injectivity characteristics will surpass that of oil formation EOR applications, and approach that of saline formations. Key process and project design parameters were extrapolated from the EOR and/or saline formation model projects.

2.5.3 Post-Combustion Capture

This model project was developed to evaluate the impacts of post-combustion capture technologies. These technologies are expected to be retrofitted to existing industrial facilities where CO_2 formed as a product of combustion of fossil fuel and air is emitted to the atmosphere as a dilute stream (typically 3-15 percent CO_2 in the exhaust stream). The separated CO_2 is transported to a geologic sequestration site for use in EOR or ECBM operations or for storage in underground saline formations. This model project only includes the capture and separation of CO_2 from a flue gas stream. The CO_2 transport and sequestration operations are discussed in separate model projects.

The following sections, which describe the model project, include these elements:

- General design and operating parameters of the project including a process diagram
- Utility requirements and generated emissions
- Site requirements and operations, and
- Construction phase activities.

2.5.3.1 General Design and Operating Parameters

The model project includes an advanced amine-based absorption system to separate CO_2 from the flue gas. As discussed in Section 3.2, this technology is commercially available and is being used to capture CO_2 from flue gas streams. Other post combustion CO_2 capture technologies that are currently being researched include, regenerable solid sorbents that chemically adsorb CO_2, physical adsorption systems that include solid sorbents operating in pressure swing adsorption (PSA) and temperature swing adsorption (TSA) modes to alternately adsorb and desorb CO_2, and gas separation membranes. These technologies are discussed in Appendix B and have not been commercially demonstrated in separating CO_2 from dilute flue gas streams.

In amine based systems, both primary and secondary amines are used in CO_2 capture processes. Monoethanolamine (MEA), considered to be the state-of-the-art technology, gives fast rates of absorption and favorable equilibrium characteristics. Secondary amines, such as diethanolamine (DEA), also exhibit favorable absorption characteristics. To reduce corrosion and amine degradation rates, and improve overall system performance, proprietary chemical inhibitors are added to MEA solutions by the technology vendors (Reddy et al, 2003, Kamijo, 2004). Another vendor uses a blend of MEA and methyldiethanolamine (MDEA), which is a tertiary amine (Chakravarti, et al, 2001). The model project described here reflects the general performance of these commercially available advanced amine based technologies.

A description of the model project parameters is included in Table 2-18. The model includes the capture of CO_2 from an exhaust slipstream of a pulverized coal-fired boiler. The boiler system is assumed to include an ESP for PM control followed by an FGD system for control of SO_2 emissions. Baseloaded boilers ranging between 200 – 500 MW capacity are assumed to be possible candidates for these technologies. Two model project sizes were selected for evaluation. At the low end, a model project that would capture CO_2 from a slip stream of the boiler exhaust was selected to represent a typical pilot-scale project that could be built under Phase II of the program. At the high end of the range, a model project was selected to represent a full-scale commercial installation. Based on these criteria, exhaust streams representative of a 10 MW pilot facility (2-5 percent slip stream of the 200-500 MW baseload boiler size range) and a 300 MW boiler were selected as the source of the captured CO_2. Exhaust flow rates shown in

Table 2-18 were based on a heat rate of 10,000 Btu/kWh typical of old Subpart D coal-fired boilers and an Fd factor of 9,780 dscf/MMBtu based on EPA Method 19 methodology.

The main exhaust stream characteristics are also shown in Table 2-21. Sulfur dioxide emissions are based on 90 percent control on Subpart D boiler (0.12 lb/MMBtu or ~ 5 ppmv at exhaust O_2 concentration of 5 percent). NO_f emissions are uncontrolled at 0.7 lb/MMBtu. Filterable PM emissions are based on uncontrolled AP-42 emission factors for a PC boiler (assuming 10 percent ash content in coal) and 99.9 percent control across the ESP. Condensable PM emissions (typically inorganic including sulphates) were based on AP-42 emission factors for PC boilers with controls. CO_2 emissions were based on exhaust CO_2 concentrations of 14 percent by volume. Assuming a CO_2 capture efficiency of 90 percent, captured CO_2 emissions range between 200 and 6,000 MT per day.

A schematic of the model project with flow rates of key streams is shown in Figure 2-4. Flue gas is passed through a blower to maintain adequate pressure required to overcome the pressure drop across the absorber. It then enters the absorption tower where it is counter-currently contacted with cool lean amine solution. CO_2 is absorbed from the flue gas stream as it passes up the column. The scrubbed flue gas exiting the absorber is washed with water, which is circulated near the top of the absorber column to minimize solvent losses, and routed to the exhaust stack. The CO_2 laden rich amine solution leaving the bottom of the absorber is heated in the rich-lean heat exchanger through indirect contact with lean solution flowing off the bottom of the stripper column.

The preheated, rich CO_2 solution enters the top of the stripper tower and flows downward and counter to the stripping agent, which is heated in a reboiler by low pressure process steam. The CO_2 is liberated from the amine solution through the application of heat. Lean solution from the bottom of the stripper is pumped to the rich-lean heat exchanger, cooled, and returned to the absorber. The vapor phase containing CO_2 and water vapor is cooled in a reflux condenser that condenses a large portion of the water vapor. The vapor CO_2 with some residual moisture is then routed to compression, dehydration, and transport.

A portion of the lean amine solution is periodically sent to a reclaimer where it is heated to a higher temperature to distill and reclaim usable solvent that is recycled to the process. Soda ash is added to aid in the precipitation of higher boiling point waste material, which includes heat stable amine salts and other degradation products. The waste is transferred to the plant’s wastewater tank for off-site disposal. Additionally, a portion of the lean amine solution returning to the absorbers is filtered using a carbon bed filter package unit.

The model projects described here do not include the compression, dehydration, and transport of CO_2 to the site of injection. A separate CO_2 transport model project (see Section 2.5.4) was developed to evaluate those impacts.

2.5.3.2 Utility Requirements

Utility requirements include steam, electricity, cooling water, and chemicals. Estimates for the model project were based on reported full-scale installation data and vendor process simulation data. A review of the literature data for MEA solvent-based CO_2 capture systems shows estimates of steam usage that range between 2.6 - 5.3 MMBtu steam per pound of CO_2 recovered. For this model project a mid-range value of 4.0 MMBtu steam/MT of CO_2 recovered was used to estimate steam requirements. Between 35 and 1,020 MMBtu/hr of low pressure steam at 50 - 60 psig is estimated for the model project.

Electricity is required to operate the flue gas blower, solvent pumps and coolers. Electricity for separation was assumed as 0.0185 MWh/MT CO_2 recovered based on literature data. This does not include energy for CO_2 compression, which can be significantly greater (about 10 times as much). Electric power requirements for the separation equipment (pumps and blower) are estimated to range between 160 - 4,730 kW and will be drawn from the plant generation capacity.

Cooling water is used primarily to wash the flue gas exiting the absorber. The water is recirculated to the process. However make-up water is added to account for losses in the system. Make-up water requirements are estimated to range between 13 and 395 gpm.

Solvent recirculation rates were assumed as 2.2 gallons solvent per pound of CO_2 removed based on data from two sources. Solvent recirculation rates were estimated to range between 690 and 20,665 gpm for the model project. Approximately 0.05 percent solvent loss is estimated from carryover and formation of heat stable salts. This equates to a make-up solvent flow rate range of 0.3 to 10 gpm required for the model project.

Soda ash (Na_2CO_3) is used to aid in the precipitation of salts in the reclaimer. Soda ash usage is estimated to range between 53 to 1,590 lb/hr.

2.5.3.3 Environmental process discharge streams

Utility requirements include steam, electricity, cooling water, and chemicals. Estimates for the model project were based on reported full-scale installation data and vendor process simulation data. A review of the literature data for MEA solvent-based CO_2 capture systems shows estimates of steam usage that range between 2.6 - 5.3 MMBtu steam per pound of CO_2 recovered. For this model project a mid-range value of 4.0 MMBtu steam/MT of CO_2 recovered was used to estimate steam requirements. Between 35 and 1,020 MMBtu/hr of low pressure steam at 50 - 60 psig is estimated for the model project.

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2.5.3.4 Site Requirements and Operations

The model project includes one absorber and regeneration train. Major equipment required under both options include, absorber and stripper towers, reboiler, pumps for rich amine, lean amine, and make-up solvent, lean/rich amine heat exchanger, solvent storage tanks, and flue gas blower.

The 10 MW equivalent pilot-scale CO_2 capture plant would include a single absorber and regeneration (stripper) train to handle the flue gas. For the larger commercial scale 300 MW facility, roughly 3 to 4 absorber and regeneration trains will be required. Each absorber train will include 3-4 absorber towers (~ 15 ft. diameter and 80 ft. in height) operating in parallel. A total of 9 - 16 absorber towers will be required. The regeneration train will consist of a total of 3 to 4 stripper towers (~ 15 ft. diameter and 75 ft. in height) operating in parallel. Each train also includes a reboiler, amine pumps, a heat exchanger, storage tanks, and a flue gas blower.

Based on the equipment required, the model project is expected to require about 5 acres of land for the pilot-scale and about 60 acres for the commercial scale facility. Availability of utilities (e.g., water, electricity, and steam) required for daily operation of the facility must be ensured. Since the capture facility will be located adjacent to an existing power plant (or other industrial facility), these utilities are expected to be available. However, the low pressure steam requirement for the commercial scale project would significantly increase the host utility boiler's heat rate.

Adequate access roads to and within the facility will be required to accommodate trucks and heavy machinery. Traffic to and from the capture facility will be infrequent compared to the host facility for the pilot-scale model project. Based on the calculated amine make-up flow rate for the 10 MW slipstream model project, roughly 15,000 gallons of aqueous solvent will be required each month. The solvent will be transported to the site once a month, in nominally 17,000 gallon tank trucks or tank rail cars depending on the available infrastructure. Additionally, soda ash consumption in the reclaimer is about 20 tons each month. Anhydrous soda ash will be supplied by truck once each week in approximately 5-ton shipments.

Liquid and solid wastes that require disposal from the pilot-scale model project include, reclaimer sludge (about 18 tons or 4,300 gallons per month) and spent carbon from the amine filter beds (about 0.5 ton per month). The reclaimer sludge is transferred to a wastewater tank and disposed off once every three months in 17,000 gallon tank trucks. Spent carbon is trucked each month to a nearby landfill for disposal.

For the larger commercial scale model project, traffic flow to the site is expected to be significantly greater. Roughly 15,000 gallons of aqueous solvent will be required each day, which would require daily deliveries in 17,000 gallon tank trucks or deliveries in significantly larger batches in rail cars each week. Soda ash consumption in the reclaimer is about 570 tons per month or about 20 tons per day, requiring four truckloads of 5-ton shipments per day.

Liquid and solid wastes that require disposal from the commercial scale model project include, reclaimer sludge (about 530 tons or 127,000 gallons per month) and spent carbon from the amine filter beds (about 16 tons per month). The reclaimer sludge is transferred to one of several wastewater tanks (about 5 – 10 tanks each of 12,000 gallon capacity) and disposed off once every two to four week period in 17,000 gallon tank trucks. Spent carbon is trucked each week to a nearby landfill for disposal.

To maintain operation of the pilot-scale facility a minimum of three personnel including, one operator, one mechanic, and an instrument technician would be required. Some of the duties of the mechanic and instrument technician could be shared between the host facility (coal-fired plant) and the model project. For round-the-clock operation of the pilot-scale model facility about six full-time equivalent skilled personnel would be required to cover three operating shifts each day.

For the commercial scale facility, about five operators (one supervisor and four train operators), three mechanics and three instrument technicians will be required. Some of the duties of the mechanic and instrument technician could be shared between the host facility (coal-fired plant) and the model project. For round-the-clock operation of the commercial scale model facility about thirty full-time equivalent skilled personnel would be required to cover three operating shifts each day.

2.5.3.5 Construction Phase Activities

The site must be prepared prior to construction. Site preparation activities would involve clearing the ground cover, which is assumed to include lightly wooded trees and brush, followed by minimal grading. A crew of six equipped with appropriate machinery including front-end loaders and chippers will take about 15 days (720 man-hours) to prepare the site.

Additional construction activities including foundations, field erection of equipment, piping, utility tie-ins (steam, electricity), commissioning, etc. would require a larger crew and heavy machinery. A crew of about 150 – 200 construction personnel would require between 6 – 9 months to complete these tasks.

For the commercial scale facility four crews of six equipped with appropriate machinery including front-end loaders and chippers will take about 45 days (8,640 man-hours) to prepare the site.

Additional construction activities including foundations, field erection of equipment, piping, utility tie-ins (steam, electricity), commissioning, etc. would require a larger crew and heavy machinery. A crew of about 500 construction personnel would require about 2 years to complete these tasks.

Erosion control measures will be implemented during construction to ensure sediment generated from construction will be controlled from impacting stormwater runoff. These measures include sufficient temporary and permanent erosion control devices and practices to control erosion and retain sediment within the boundaries of the site.

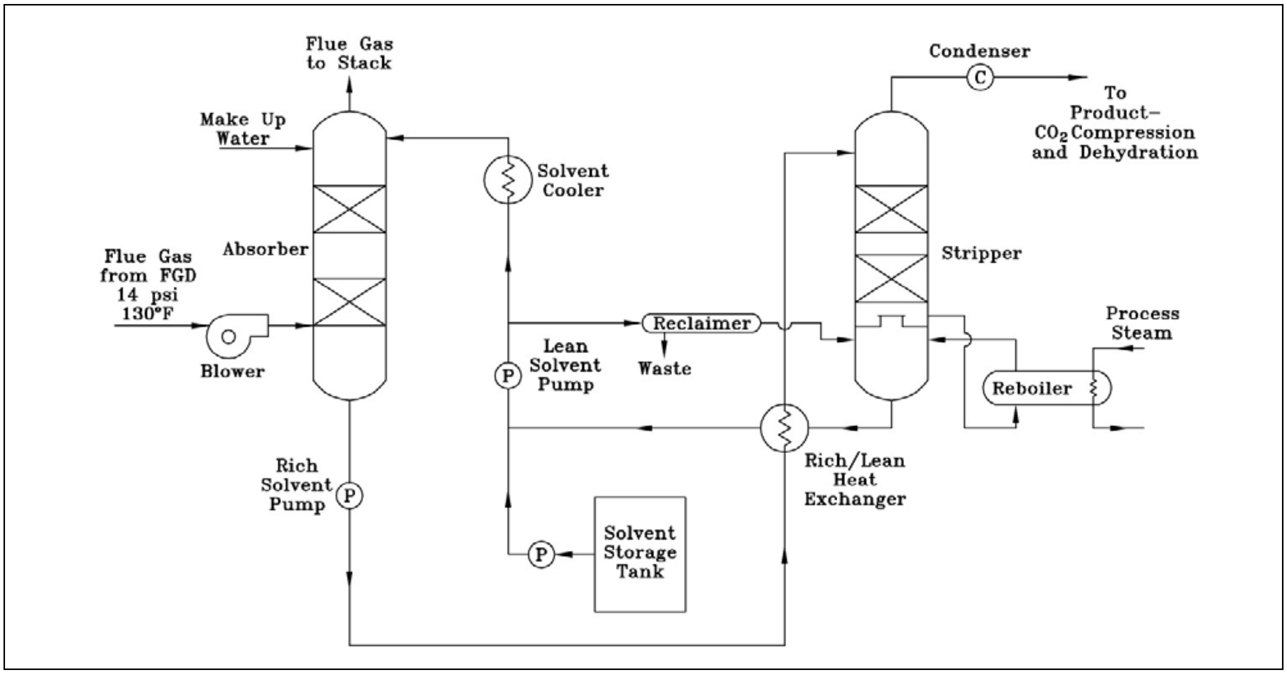


Figure 2-4. Schematic of Post-Combustion Capture Model Project

Table 2-18. Post Combustion Capture Model Project Data Sheet

Parameter	Description/ Basis	Low	High
Description of Model Plant	Model Plant includes the capture of CO_2 from a slip-stream of a pulverized coal-fired boiler equipped with wet FGD and ESP. Exhaust treatment options include advanced amine absorption. Following separation the CO_2 is sent for dehydration and compression to injection pressures of about 3000 psi.		
Boiler Size (MW)	Based on expected size range	200	500
Slip Stream characteristics			
Slip stream (MW equivalent)	Based on 2-5 % slip stream for a pilot-scale installation at the low end to a typical 300 MW commercial scale installation at the high end.	10	300
Slip Stream (MMBtu/hr equivalent)	Based on a heat rate of 10,000 Btu/kWh	100	3,000
Flow Rate (dscf/hr)	Based on an F_d-factor of 9,780 dscf/MMBtu (USEPA Method 19)	978,000	29,340,000
Slip Stream Gas Composition			
SO_2 (lb/hr)	Based on 90 percent control for Subpart D solid fuel boiler (i.e., 0.12 lb/MMBtu emission rate)	12	360
NO_f (lb/hr)	Based on a NO_f emission rate of 0.7 lb/MMBtu per NSPS Subpart D	70	2,100
PM Filterable (lb/hr)	Based on AP-42 uncontrolled emission factor and 99.9 percent control (i.e., 0.004 lb/MMBtu)	0.4	12
PM condensibles (lb/hr)	Based on AP-42 emission factor	2	60
CO_2 (lb/hr)	Based on exhaust gas concentration of 14 percent by volume	20,872	626,171
Processes:	Flue gas captured from vent stack is treated in amine absorption/regeneration or other adsorption/regeneration trains to separate CO_2, which is sent for dehydration and compression.		
Major Equipment:	Flue gas cooler, absorber tower, amine storage tanks, rich/lean heat exchanger, amine stripper, reboiler, condenser, pumps, blower		
Operating Utilities	Steam, electricity, cooling water, chemicals makeup		
CO_2 captured (lb/hr)	Assuming 90 percent capture efficiency	18,800	563,600
CO_2 captured (MT per day)		205	6,134
Utility and chemical requirements			
Steam (MMBtu/hr)	Based on the following range Praxair (Chakravarti et. al., 2001) =4 to 5 MMBtu/MT CO_2 recovered. SFA (Simbeck, 2001) = 2.6, EPRI (Case 7A) = 4.8, Nexant (Chinn et. al., 2004) = 5.3. RITE (Morimoto, et. al., 2002) =3.2 Used mid-range value of 4.0 for the model project.	34	1,022
Electricity (kW)	Based on energy for separation of 0.0185 kWh/kg CO_2 recovered (Morimoto, et.al., 2002)	160	4,730
Water (gpm)	Based on 180 gpm required for 2,800 MT per day recovered CO_2 plant.	13	394
Water use (gals/day)		18,720	567,360
Solvent Recirculation rate (gpm)	Based on recirculation. rate of 2.2 gal MEA solution/lb CO_2 removed – (EPRI study, case 7A); Chinn et. al., 2004 = 2.18.	689	20,664
Solvent make-up (gpm)	Based on 0.05 per cent loss (Chinn et. al., 2004)	0.34	10.3
Solvent Delivery (gals/day)		500	15,000
Soda Ash (lb/hr)	Based on 168 kg/hr for a 4800 gpm solvent recirculation rate (Chinn et. al., 2004)	53	1,591
Wastes generated			
Reclaimer sludge (lb/hr)	Based on 5000 MT/yr sludge for a 5200 MT per day recovered CO_2 plant (Simmonds, et. al., 2003)	50	1,485
Spent Carbon (lb/hr)	Based on 114 kg/day for 4800 gpm solvent recirculation rate (Chinn et. al., 2004)	1.50	45
Physical Attributes			
Land Requirement (Acres)		5	60

2.5.4 CO_2 Transport Model Projects

These model projects were developed to evaluate the impacts of transporting CO_2 to a sequestration site. Two options are evaluated. The first option involves the compression and transport of a CO_2 stream to a commercial-scale sequestration site that is located within 20 miles of the CO_2 capture site. In this option CO_2 is obtained following separation from a flue gas stream or is obtained as a pure CO_2 stream from natural gas processing or ethanol plants. Alternatively, the CO_2 gas stream obtained from IGCC plants or sour gas processing facilities contain significant quantities of H_2S and require compression and transport prior to sequestration in saline formations or EOR projects.

In the second option, CO_2 is transported in tank trucks to sequestration sites that are not located close to a CO_2 capture site or a CO_2 pipeline. These models describe facilities will be required to supply CO_2 at required injection pressures in pilot-scale projects that demonstrate the feasibility of CO_2 sequestration operations.

The following sections, which describe the model projects, include these elements:

- General design and operating parameters of the project including a process diagram
- Utility requirements and generated emissions
- Site requirements and operations, and
- Construction phase activities.

2.5.4.1 Case A: Compression and Transport of Captured CO_2 by Pipeline

2.5.4.1.1 General Design and Operating Parameters

CO_2 that is obtained from sweet gas plants or separated from flue gas streams is typically at atmospheric pressure and contains 96-98 percent CO_2, 1-3 percent moisture, and traces of other compounds. For example, CO_2 obtained from sweet gas plants could contain methane (CH_4) and traces of hydrogen sulfide (H_2S). CO_2 gas streams obtained from IGCC plants and/or sour gas processing facilities contain up to 45 percent H_2S.

Table 1-1 shows the CO_2 gas parameters. The gas stream parameters and analysis shown in the table reflect an almost pure CO_2 gas stream containing negligible quantities of H_2S. Differences in results caused by the high H_2S concentration case are discussed as appropriate. Two model project sizes were selected for analysis. At the low end is a transport model project capable of handling about 200 MT CO_2 per day, which is representative of the volume captured from a pilot-scale CO_2 capture project. At the high end, the transport model is capable of handling about 2,740 MT CO_2 per day, which is representative of the volume required for typical commercial scale geologic sequestration operations. The gas is assumed to contain 96 percent CO_2, 3 percent H_2O, and 1 percent of other constituents. Prior to transport and injection, the CO_2 is compressed and dehydrated to meet pipeline specifications. Figure 2-5 shows a schematic of the model project. CO_2 at atmospheric pressure is compressed to a discharge pressure of about 1400 psi using a 4-stage compressor unit with interstage coolers and water knockouts. At this pressure, CO_2 behaves as a liquid and further compression to injection pressures of about 3000 psig is achieved using a single-stage pump unit. Between the third and fourth stages of compression, CO_2 gas is dehydrated in a triethylene glycol (TEG) dehydrator unit.

For the transport of the high H_2S concentration acid gas streams, the CO_2 flow rate depends on the concentration of CO_2 in the gas stream. The low-end transport model gas stream is assumed to contain about 2 percent H_2S, which corresponds to a slip stream from an IGCC or sour gas processing plant. The CO_2 flow rate is approximately 200 MT per day. For the commercial scale transport model the gas stream is assumed to contain about 25 percent H_2S (by weight), which corresponds to a typical commercial scale sour gas processing plant. The CO_2 flow rate is about 2055 MT per day.

Compression of the acid gas stream prior to transport and injection can be achieved using a 4-stage compressor unit similar to the compression of pure CO_2 stream shown in Figure 2-5. Depending on the H_2S content and gas temperature, the solubility of water in the gas decreases with increasing pressure (Bachu and Gunter, 2004). Therefore compression above 450 and 750 psig tends to naturally dewater the gas, thereby avoiding the need for dehydration using TEG.

2.5.4.1.2 Operating Utilities and Materials

For the model project, energy is required to operate the compressors and pump. Based on availability of natural gas fuel or electricity, the compressors and pump can be driven either by gas-fired internal combustion (IC) engines or by electric motors. A small quantity of gas fuel is also required to operate the reboiler in the dehydrator unit. Based on compressor operating parameters and gas conditions, energy usage was calculated as 6,700 kWh/MMscf compressed gas assuming that electric-drive motors are used as prime movers for the compressors and pump. If natural gas is used as fuel for gas-fired engine prime movers, energy usage is estimated as 72 Btu/scf gas compressed based on engine brake specific fuel consumption (bsfc) of 8,000 Btu/hp-hr. These estimates of energy usage are consistent with values in the published literature (Morimoto, et. al., 2002). Dehydrator fuel usage is small in comparison, estimated to be about 0.5 Btu/scf gas processed.

Energy requirements are similar for the acid gas compression assuming similar suction and discharge pressures. Actual discharge pressures depend on formation conditions. Since a dehydration step may not be required, it will result in dehydrator fuel usage savings.

To maintain operation of IC engines, lubrication oil and cooling water are required. Based on installed capacity of 2,000 hp for the pilot-scale and 25,000 hp for the commercial scale installation (requirement is 1,400 – 20,000 hp), lubricating oil consumption is estimated at 12 - 150 gallons per day.

2.5.4.1.3 Environmental Process Discharge Streams

The use of natural gas as fuel for the IC engines results in emissions of CO_2, CH_4, and criteria pollutants, including NO_f, CO, and VOCs. CO_2 emissions vary between 1,260 – 17,200 lb/hr and methane emissions range between 17 - 227 lb/hr. Assuming a global warming potential for CO_2 of 1 and for CH_4 of 21, the CO_2 equivalent (CO_2 e) emissions range between 1,600 – 21,950 lb/hr, which is about 9 percent of the CO_2 compressed. NO_f emissions range between 36 - 495 lb/hr, CO emissions range between 4 - 60 lb/hr, and VOC emissions range between 1.4 – 19 lb/hr.

Condensate from the compressed gas stream is generated at rates that range between 200 – 2,900 lb/hr. The condensate is transferred to a wastewater tank for off-site disposal. Based on engine maintenance schedules, used engine oil wastes are generated. Between 150 – 1,875 gallons of used oil is generated every four months (assuming an oil change every 3,000 hrs of operation). The oil is transferred to a waste oil tank for periodic off-site disposal.

Additional liquid wastes include oils and grease used for maintenance activities. Similar waste streams are typically generated at utility and industrial facilities and the incremental quantities of oil and grease wastes generated by the model project will not require significant additional waste handling measures.

2.5.4.1.4 Site Requirements and Operations

The pilot-scale model project includes about 4 engine-compressor units and one pump unit with a total installed capacity of about 2,000 hp. If electric-drive motors are used instead of IC engine-driven compressors, five motors with a total installed capacity of about 1,500 kW are required. The compressor units will be housed in a compressor building with an approximate plan dimension of 50 feet by 100 feet. A TEG dehydration system capable of processing 4 MMscfd of CO_2 gas is required. The system includes contactor and stripper towers, reboiler, TEG pumps, heat exchanger, and solvent storage tanks.

Additional space to accommodate piping manifolds, knockouts, and wastewater and used oil tanks is required.

The commercial scale model project includes about 8-10 engine compressor units and 2 pump units with the total installed capacity of about 25,000 hp. If electric-drive motors are used instead of IC engine-driven compressors, about 10 - 12 motors with a total installed capacity of about 19,000 kW are required. The compressor units will be housed in about 5 compressor buildings each with an approximate plan dimension of 50'x100'. A TEG dehydration system capable of processing about 55 MMscfd of CO_2 gas is required. The dehydration system equipment is similar to that described for the pilot scale model project but will have much larger dimensions to accommodate the increased gas flow rates.

Based on the equipment required, the pilot-scale model project is expected to require about 2 acres of land. Availability of utilities (e.g., electricity, natural gas, and water) required for daily operation of the facility must be ensured. Since the compression and transport facility will be located adjacent to an existing industrial facility, these utilities are expected to be available.

To accommodate the larger plant size, the commercial scale model project is expected to require about 20 acres of land. Availability of utilities (e.g., electricity, natural gas, and water) required for daily operation of the facility must be ensured. If electric motors are used to drive the compressors, electric power of ~ 15 MW will be required. If natural gas-fired engines are used to to drive the compressors, total engine heat input is estimated as156 MMBtu/hr (~150,000 scf/hr natural gas). The CO_2 compressor station will require access to the local grid and natural gas pipeline delivery.

Adequate access roads, to and within the facility, will be required to accommodate trucks and heavy machinery. Traffic to and from the facility will be infrequent. Water condensed from the gas will be transferred to a wastewater tank. Wastewater will be disposed off once a month for the pilot facility and once every two days for the commercial scale facility in 17,000-gallon tank trucks.

Used engine lubricating oil will be transferred to a used oil tank and disposed off once every six months for the pilot facility and once a month for the commercial scale facility.

To maintain operation of the pilot-scale facility a minimum of three personnel including, one operator, one mechanic, and an instrument technician would be required. Some of the duties of the mechanic and instrument technician could be shared between the host facility and the model project. For round-the-clock operation of the model facility about six full-time equivalent skilled personnel would be required to cover three operating shifts each day.

The commercial scale facility will require about three operators, two mechanics, and two instrument technicians. For round-the-clock operation about 20 full time equivalent skilled personnel would be required to cover three operating shifts each day

2.5.4.1.5 Construction Phase Activities

The site must be prepared prior to construction. Site preparation activities would involve clearing the ground cover, which is assumed to include lightly wooded trees and brush, followed by minimal grading. A crew of six equipped with appropriate machinery including front-end loaders and chippers will take about 7 days (336 man-hours) to prepare the site.

Additional construction activities including foundations, field erection of equipment, piping, utility tie-ins (natural gas, electricity), commissioning, etc. would require a larger crew and heavy machinery.

For the small-scale pilot transport model project, about 0.25 miles of 6-inch carbon steel pipeline would be buried underground to transport the pure CO_2 stream to the sequestration site (e.g., a slip-stream from a major CO_2 source to a geologic sequestration location, either co-located on the same site or on an adjacent industrial property). Approximately 50 feet of a 75 foot existing right of way would be disturbed for pipeline construction activities (both for the pilot and commercial scale facility). For transport of acid gas carbon steel can be used although stainless steel is preferred because of the corrosive nature of the

H_2S in the stream. Usually 304/316L stainless steel is employed for best corrosion resistance (Carroll, 1999). A crew of about 25-50 skilled construction personnel would require about 8 months to complete these tasks.

For the commercial scale facility, three crews of six each equipped with appropriate machinery including front-end loaders and chippers will take about 25 days (3,600 man-hours) to prepare the site.

Additional construction activities including foundations, field erection of equipment, piping, utility tie-ins (natural gas, electricity), commissioning, etc. would require a larger crew and heavy machinery. About 20 miles of about 8-inch pipeline would be buried underground to transport the CO_2 to the sequestration site. For transport of acid gas, use of stainless steel pipeline is preferred. A crew of about 100 skilled construction personnel would require about 12 to 18 months to complete these tasks.

Erosion control measures will be implemented during construction to ensure sediment generated from construction will be controlled from impacting stormwater runoff. These measures include sufficient temporary and permanent erosion control devices and practices to control erosion and retain sediment within the boundaries of the site.

2.5.4.2 Case B: Compression and Transport of Liquified CO_2 by Refrigerated Tank Trucks

2.5.4.2.1 General Design and Operating Parameters

For sequestration projects that are not located near CO_2 capture sites or near existing CO_2 pipelines, liquid CO_2 can be transported to the sequestration site in tank trucks. A schematic of the model project is shown in Figure 2-6. Liquid CO_2 is delivered in commercial refrigerated tank trucks that travel about 100 miles (roundtrip) to the sequestration site. Each truckload is capable of supplying about 20 MT of CO_2. At the sequestration site CO_2 is transferred to large storage tanks that are maintained at about 300 psig and 0 deg F.

The CO_2 is further compressed to injection pressures by skid-mounted pumps located at the sequestration site. In certain cases, if CO_2 gas injection is required, vaporizer units will be required. Vaporizers are not included in this model plant.

2.5.4.2.2 Operating Utilities and Materials

Liquid CO_2 from the supply tank trucks is pumped to the on-site storage tanks by individual truck-mounted pumps. Electricity is required to operate the on-site pumps that compress CO_2 from tank pressures of 300 psig to injection pressures of about 3,000 psig. Based on the injection rates of about 100 – 200 MT/day, electric power requirements are estimated as 75 –150 kW (Table 2-20). If natural gas-fired IC engines are used to drive the pumps, fuel requirements are estimated as 10 MMBtu/MMscf gas compressed, based on an engine bsfc of 8,000 Btu/hp-hr.

To maintain operation of IC engines, lubrication oil and cooling water are required. Based on installed capacity of 150-300 horsepower (requirement is 100-200 hp), lubricating oil consumption is estimated at 0.6 - 1.2 gallons per day.

2.5.4.2.3 Environmental Process Discharge Streams

The use of natural gas as fuel for the IC engines results in emissions of CO_2, CH_4, and criteria pollutants, including NO_f, CO, and VOCs. CO_2 emissions vary between 87 - 175 lb/hr and methane emissions range between 1.2 – 2.3 lb/hr. Assuming a global warming potential for CO_2 of 1 and for methane of 21, the CO_2 equivalent emissions range between 111 and 222 lb/hr, which is about 1 percent of the CO_2 compressed and ultimately sequestered. NO_f emissions range between 3 - 5 lb/hr, CO emissions range between 0.3 – 0.6 lb/hr, and VOC emissions range between 0.1 – 0.2 lb/hr.

The project also results in mobile source emissions from the commercial tank trucks supplying liquid CO_2 to the sequestration site. Assuming the supply facility is located about 50 miles from the sequestration site (i.e., 100 - mile round-trip), CO_2 emissions from gasoline fuel combustion in the supply truck were estimated to range between 70 – 140 lb/hr. Methane and nitrous oxide (N_2O) emissions were lower. The CO_2e emissions (assuming a GWP of 310 for N_2O) are estimated to range between 80 – 160 lb/hr or less than 1 percent of the CO_2 compressed and ultimately sequestered. NO_f emissions range between 0.1 – 0.3 lb/hr and CO emissions range between 0.7 – 1.3 lb/hr.

Based on engine maintenance schedules, used engine oil wastes are generated. About 25 - 40 gallons of used oil is generated every four months (assuming an oil change every 3,000 hrs of operation). The oil is transferred to a waste oil tank for periodic off-site disposal.

Additional liquid wastes include oils and grease used for maintenance activities. Similar waste streams are typically generated at utility and industrial facilities and the incremental quantities of oil and grease wastes generated by the model project will not require significant additional waste handling measures.

2.5.4.2.4 Site Requirements and Operations

The model project includes about 3 to 4 IC engine-driven pump units with a total installed capacity ranging between 150 - 300 hp. Electric-drive motors (115 – 225 kW) can be used instead of IC engines to provide power for operating the pumps. The pumps will be housed in a building with an approximate plan dimension of 50'by 50'. Between 2 to 4 large insulated tanks are required to store the liquid CO_2 supplied by the tank trucks. Additional space to accommodate CO_2 supply tank trucks, piping and manifolds, and used oil tanks is required.

Based on the equipment required, the model project is expected to require about 1 acre of land. Availability of utilities (e.g., electricity, natural gas, and water) required for daily operation of the facility must be ensured.

Adequate access roads, to and within the facility, will be required to accommodate trucks and heavy machinery. Traffic to and from the facility will be frequent. Based on a truckload of 20 MT of CO_2, between 5-10 truckloads are required each day. Used engine lubricating oil will be transferred to a used oil tank and disposed off once every six months.

To maintain operation of the facility a minimum of three personnel including, one operator, one mechanic, and an instrument technician would be required. Some of the duties of the mechanic and instrument technician could be shared between the sequestration facility and the model project. For round-the-clock operation of the model facility about six full-time equivalent skilled personnel would be required to cover three operating shifts each day.

2.5.4.2.5 Construction Phase Activities

No additional construction activities beyond that of the existing geologic sequestration facility in question would be required for truck transport of CO_2.

Table 2-19. Model A: Captured CO_2 Compression and Transport Model Project Data Sheet

Parameter	Description/ Basis	Low	High
Description of Model Project	Model plant includes the compression and dehydration of CO_2 that is captured at atmospheric pressure. CO_2 is compressed to an injection pressure of 3,000 psi and used in geologic sequestration activities. (i.e, enhanced oil recovery, enhanced coalbed methane, or storage).		
Slip Stream characteristics			
Flow Rate (lb/hr)	Low end of range based on 200 MT per day (~10 MW slip stream) capture CO_2 pilot-scale facility. High end of range based on 2,700 MT per day (~ 1,000,000 MT per year) commercial scale geological sequestration operation.	18,375	251,700
Flow Rate (MT/day)		200	2,740
Flow Rate (MT/Year)		73,000	1,000,100
Flow Rate (scf/day)		3,802,623	52,090,722
CO_2 (lb/hr)	Based on 96 percent CO_2 by volume	17,640	241,644
Moisture (lb/hr)	Based on 3 percent water by volume	226	3,089
Processes:	CO_2 that is captured and separated from flue gas is compressed and dehydrated to injection pressures of 3,000 psi for use in geologic sequestration activities. The model assumes that the CO_2 source is within 10 miles from the point of injection		
Major Equipment:	CO_2 gas compressors (IC engine or electric motor driven), intercoolers, and associated auxiliary equipment, dehydrator, water knockouts, up to 20 miles of pipeline,		
Operating Utilities	Natural gas fuel and/or electricity		
Operating Utilities and Materials			
Natural Gas Fuel -IC Engines (MMBtu/hr)	Based on 72 MMBtu/MMscf CO_2	11.4	156
Natural Gas Fuel - Dehydrator (MMBtu/hr)	Based on 0.5 MMBtu/MMscf of CO_2 processed	0.08	1.1
Electric power- Motors (kW)	Based on 6,700 kWh/MMscf CO_2 compressed	1,062	14,542
Lubricating oil (gal/day)	Based on 0.5 gal/hr for a 2,000 hp unit	12	156
Emissions from IC Engine combustion			
CO_2 (lb/hr)	Emission factor (EF) =110 lb/MMBtu (USEPA AP-42 Table 3.2-1)	1,255	17,190
CH4 (lb/hr)	Emission factor (EF) =1.45 lb/MMBtu (USEPA AP-42 Table 3.2-1)	17	227
NO_f (lb/hr)	Emission factor (EF) = 3.17 lb/MMBtu (USEPA AP-42 Table 3.2-1)	36	495
CO (lb/hr)	Emission factor (EF) =0.386 lb/MMBtu (USEPA AP-42 Table 3.2-1)	4.4	60
VOC (lb/hr)	Emission factor (EF) =0.12 lb/MMBtu (USEPA AP-42 Table 3.2-1)	1.4	19
Wastes generated			
Water discharge (lb/hr)	Based on pipeline spec. of 4 lbs H_2O/MMscf	210	2,880
Water discharge (gal/day)	Converted lbs to gallons	604	8,283
Used lubricating Oil (gal/month)	Based on 100-150 gallons per oil change every 3,000 operating hrs.	38	470
Physical Attributes			
Land Requirement (Acres)	Land for compressor facilities	2	20
Pipeline Disturbance (Acres)	Assumes 50' of a 75' corridor would be disturbed. Minimum case is 0.25 miles and Maximum case is 20 miles	1.5	121
Total Land Disturbance (Acres)	Facilities and Pipeline	3.5	141

Table 2-20. Model B: Liquid CO_2 Transport Model Project Data Sheet

Parameter	Description/ Basis	Low	High
Description of Model Project	Model plant includes the storage of liquid CO_2 that is transported to the sequestration site by commercial refrigerated tank trucks. The CO_2 is pumped to injection pressures of 3,000 psig at the site prior to injection in geologic sequestration activities. (i.e, enhanced oil recovery, enhanced coalbed methane, or storage).		
Supply Rate (MT/day)	Based on similar flow rate as captured CO_2 transport volumes	100	200
Truckloads per day	Based on 20 MT per truckload	5	10
Processes:	CO_2 is supplied by refrigerated tank trucks to the sequestration site where it is transferred to one or more large insulated tanks maintained at 300 psig. At the site, a pumping station that includes 3-4 pumps is used to pump the liquid CO_2 at injection pressures of about 3,000 psig. The model assumes that the CO_2 supply tank trucks travel about 100 miles round trip.		
Major Equipment:	Insulated CO_2 storage tanks, CO_2 pumps (IC engine or electric motor driven).		
Operating Utilities	Natural gas fuel and/or electricity		
Operating Utilities and Materials			
Fuel -IC Engines (MMBtu/hr)	Based on 10 MMBtu/MMscf CO_2	0.8	1.6
Electric power- Motors (kW)	Based on 930 kWh/MMscf CO_2 compressed	74	147
Lubricating oil (gal/day)	Based on 0.5 gal/hr for a 2,000 hp unit	0.60	1.20
Emissions from Stationary IC Engine combustion			
CO_2 (lb/hr)	Emission factor (EF) = 110 lb/MMBtu (USEPA AP-42 Table 3.2-1)	87	174
CH_4 (lb/hr)	Emission factor (EF) = 1.45 lb/MMBtu (USEPA AP-42 Table 3.2-1)	1.2	2.3
NO_f (lb/hr)	Emission factor (EF) = 3.17 lb/MMBtu (USEPA AP-42 Table 3.2-1)	2.5	5
CO (lb/hr)	Emission factor (EF) = 0.386 lb/MMBtu (USEPA AP-42 Table 3.2-1)	0.3	0.6
VOC (lb/hr)	Emission factor (EF) = 0.12 lb/MMBtu (USEPA AP-42 Table 3.2-1)	0.1	0.2
Mobile Source Emissions			
CO_2 (lb/hr)	Based on 100 mile round trip @ 6 mpg and EF = 0.0709 MT/MMBtu (API Compendium, Table 4-1)	71	141
CH_4 (lb/hr)	Based on 100 mile round trip @ 6 mpg and EF = 6.4×10^{-4} MT/1000 gal (API Compendium, Table 4-9)	0.01	0.01
N_2O (lb/hr)	Based on 100 mile round trip @ 6 mpg and EF = 3.8×10^{-3} MT/1000 gal (API Compendium, Table 4-9)	0.03	0.06
NO_f (lb/hr)	Based on 100 mile round trip and EF = 3.02 g/mile (USEPA AP-42, Appendix H, Table 4.1A.1)	0.1	0.3
CO (lb/hr)	Based on 100 mile round trip and EF = 14.23 g/mile (USEPA AP-42, Appendix H, Table 4.1A.1)	0.7	1.3
Wastes generated			
Used lubricating Oil (gal/month)	Based on 25 - 40 gallons per oil change every 3,000 operating hrs.	6.25	10

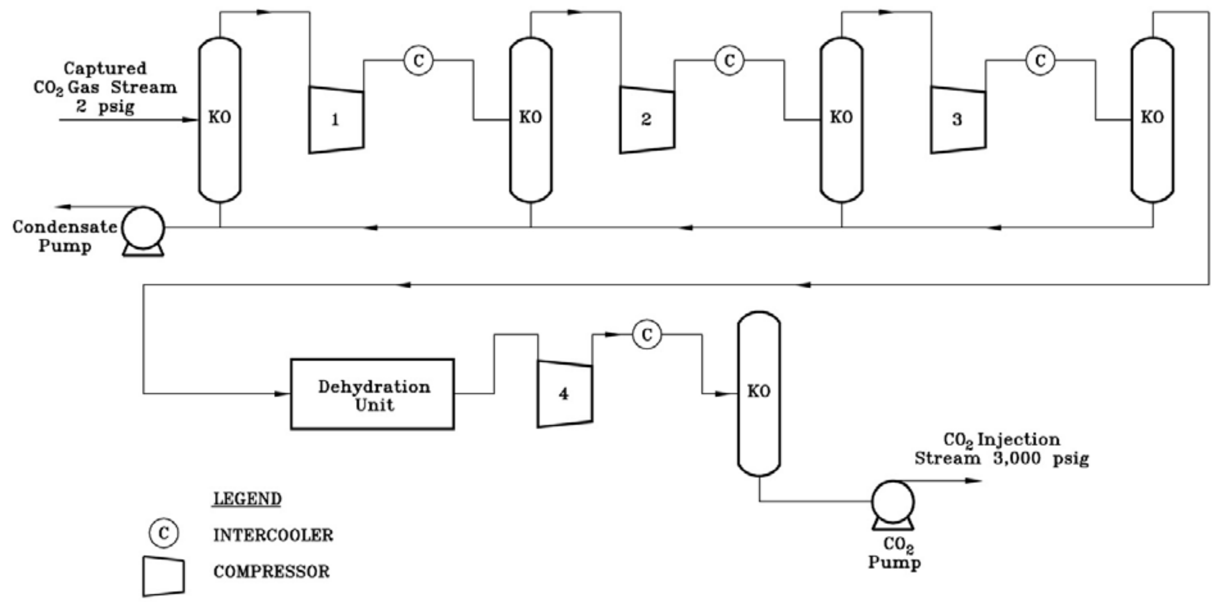


Figure 2-5. Schematic of Captured CO_2 Compression and Transport Model Project (Model A)

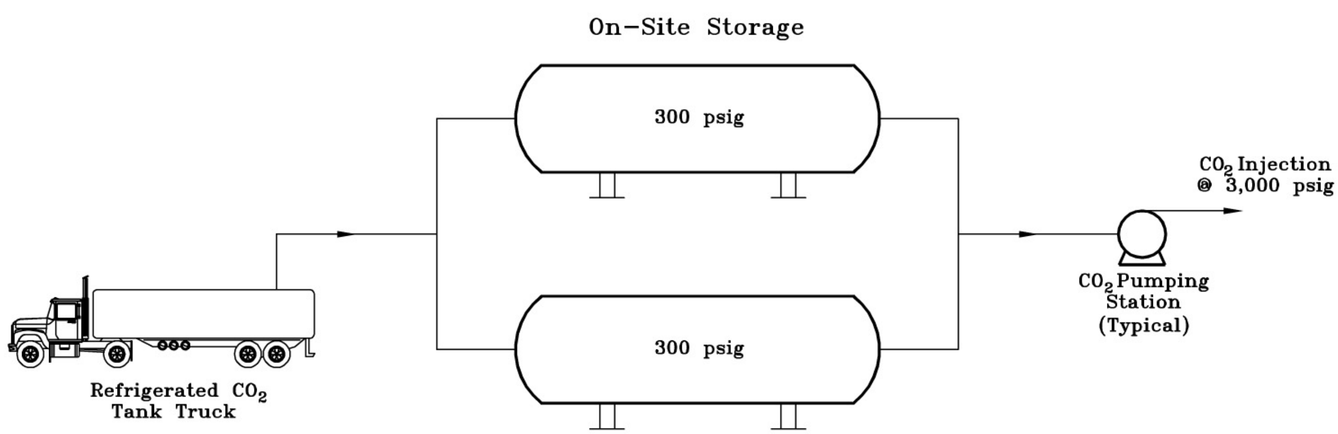


Figure 2-6. Schematic of Refrigerated CO_2 Transport and Compression Model Project (Model B)

2.5.5 Coal Seam Sequestration and Enhanced Coalbed Methane Recovery Model Project

This model project was developed to evaluate the impacts of CO_2 sequestration in deep, unmineable coal seams. The coal seam sequestration model project would consist of transporting CO_2 on site from a nearby source, heating and regulating the pressure of the CO_2, and injecting CO_2 into the coal seams. Although methane recovery may not be appropriate for all locations at which this model project may be implemented, recovering marketable coalbed methane (CBM) would be addressed in this model project description.

Coal seam sequestration of CO_2 has occurred in two known pilot projects in the U.S. Therefore, the technology to operate coal seam CO_2 sequestration projects has been developed. These projects have operated with appropriate permits and approvals, as applicable by their respective states, including completing the NEPA review process and acquiring environmental permits, such as an air quality permit. Additional descriptions of current sequestration technologies are discussed in Section 2.2.

The following sections, which describe the model project, include these elements:

- General design and operating parameters including Monitoring, Mitigation, and Verification (MM&V);
- Utility requirements;
- Environmental process discharge streams;
- Site requirements and operations; and
- Construction phase activities.

2.5.5.1 General Design and Operating Parameters

Favorable project conditions have been narrowed to a range of values to provide flexibility of project placement. These ranges have been derived from review of existing pilot projects of CO_2 and nitrogen (N_2) injection into coal seams, as well as geological recommendations from team personnel. The three existing pilot projects that were reviewed are the Allison Unit CO_2 Project and the Tiffany Unit N_2 Project, both conducted in the San Juan Basin in New Mexico and Colorado, and the CONSOL Energy CO_2 project in West Virginia. All three projects also recovered CBM.

A description of the model project parameters is included in Table 2-21. CO_2 injection at the Allison Unit averaged 232 tons per day from four wells. CONSOL Energy will conduct a small scale research and design project in West Virginia which expects an averaged injection rate of 36 tons of CO_2 per day. To ensure the model project encompasses injection rates similar to the above examples, the following range of CO_2 average daily injection rates would be used: 35 tons/day (11,590 MT per year) as a minimum from one well and 2,750 tons/day (910,600 MT per year) as a maximum from twelve wells.

The number of injection wells would range from 1 to 12. This range is based on the Allison Unit project for the minimum value, and an average daily injection rate of 230 tons/day from a single well (Allison Unit) for the maximum value. The majority of other project data (number of CBM production wells, site acreage, miles of access roads, etc.) is based off of the number of injection wells. The number of CBM recovery wells range from 2 to 20, based on either a 3-spot configuration like the CONSOL project or a 5-spot configuration (see Figure 2-7). Between 1 and 8 monitoring wells would be installed for various MM&V requirements. All wells would be new construction.

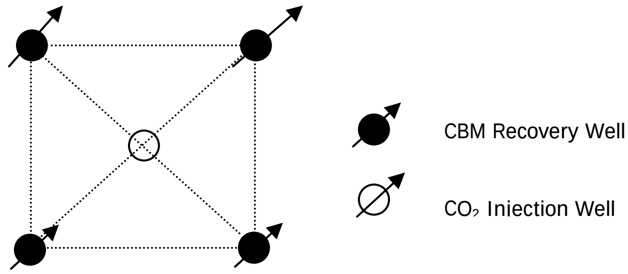


Figure 2-7. Typical 5-Spot Well Configuration

Depending on the depth of the coal seam, wells may extend from 1,000 to 2,500 feet in depth, with the coalbed ranging from 10 feet to 200 feet thick. The United Mine Workers of America (UMWA) website states that almost all underground coal mines in the U.S. are less than 1,000 feet deep; therefore, this was used as the minimum depth value. 2,500 feet is the maximum depth as it is the deepest active mine in the U.S. (Alabama). The question of whether a coal seam is mineable or not depends on location, depth specifics, economic feasibility, and ownership of the coal, as industry will determine what is mineable and what are future coal reserves. The ranges for the coal seam thickness are based on the Allison Unit for a minimum and geologic input for the maximum. Single coal seams of 40 – 200 feet are specific to the western states. Coal seams in the east can vary from 2 – 7 feet thick, so multiple seams are ideal.

A range of 0.02 mile to 4.1 miles of 4-inch piping would be required to distribute the CO_2 to individual wells on site. This maximum value assumes the distribution lines would begin at one central location and distribute out to two main distribution lines which would feed to the individual injection wells. It is assumed that 50 percent of needed piping exists in existing production right-of-ways. New piping would be placed in new road right-of-ways. As discussed later, injection and recovery wells are a maximum of 1,800 feet apart. This piping would be buried to insure that seasonal temperatures do not affect line pressures, and thus injection rates. This dispersion system would connect to individual well sites via a 2-inch pipe.

The types of surface equipment for both CO_2 injection and CBM production anticipated for the model project are discussed in the following paragraphs. The surface configuration for a CO_2 injection well would consist of the following equipment (see Figure 2-8 for a flow diagram). The Compression and Transport of Captured CO_2 Model Project Description compresses the gas stream to 3,000 psia. A gas-fired heating unit would be anticipated as the CO_2 would most likely require heating to raise the temperature to equal that of the coalbed (Reeves et al., 2003). Following the heating unit is a pressure regulator, which would ensure constant pressure of the CO_2. A flow meter would regulate the injection rate, and a Supervisory Control and Data Acquisition (SCADA) system would monitor and transmit flow rate, pressure, and temperature information to a central data collection point. The SCADA system would be solar powered with a battery backup. The footprint for the CO_2 injection surface configuration is anticipated to be about 150 square feet.

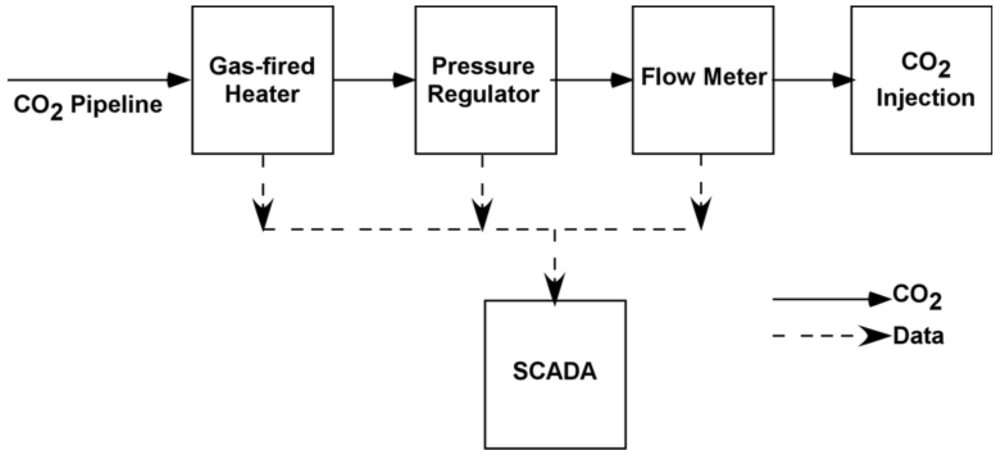


Figure 2-8. CO_2 Injection Well Surface Configuration

The surface configuration for a CBM production well would consist of a gas/water separator, surface pressure regulation, gas flow meter, a SCADA system, and produced water storage, as shown in the flow diagram in Figure 2-9 (Reeves et al., 2004). Storage tanks with a total estimated storage capacity ranging from 500 gallons to 10,000 gallons would store water recovered during CBM recovery until it can be transported off-site for treatment and discharge. Assuming wastewater generation of these storage capacities per week derives a minimum of 2.98 gallons per hour and a maximum of 59.5 gallons per hour. Two additional options to wastewater discharge include reinjection at greater depths, as long as the water below the coal seam is of lesser quality, or use of a submerged evaporator to evaporate the water leaving salt for disposal. The estimated footprint for the CBM recovery surface configuration is approximately 1,600 square feet. On-site compression is not currently anticipated for the recovered CBM. A pipeline would transport the CBM off-site for CO_2 removal and compression for transmission.

Prior to injection, various methods of MM&V can be conducted to form a data baseline of the coal seam, groundwater formations, surface water, and gas monitoring. These technologies are then continued during injection, and for extensive time periods following injection. MM&V technologies may include seismic tomography and monitoring, measurement of in-situ temperature and pressure, and electromagnetic imaging.

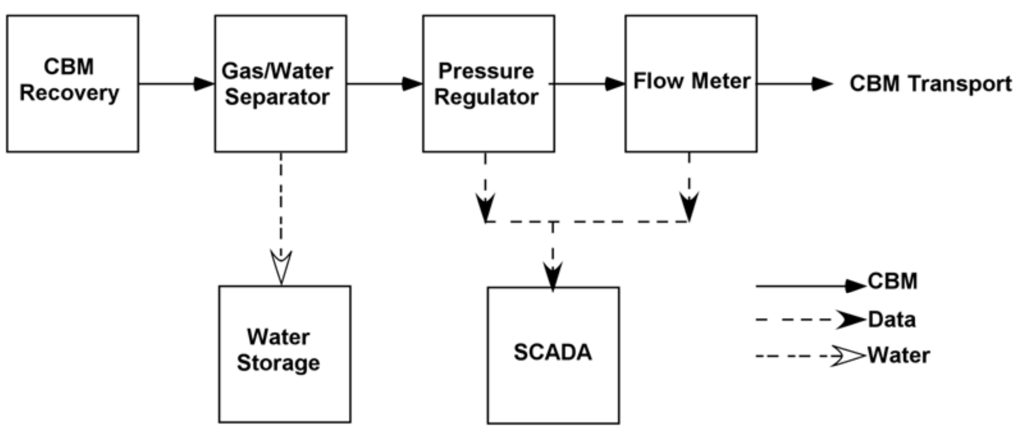


Figure 2-9. CBM Production Well Surface Configuration

2.5.5.2 Utility Requirements

Utility requirements for the model project include fuel usage. Fuel would be trucked on site for the injection well heating unit. The estimated annual distillate fuel usage is 2,884 gallons for the minimum scenario and 226,560 gallons for the maximum scenario. No additional on-site fuel storage is anticipated.

The annual electricity usage rates for CO_2 Enhanced Oil Recovery (EOR) operations as discussed in the EOR Model Project description is estimated at 1.86 hp per million standard cubic feet (MMscf). This usage rate value includes CO_2 compression, pumping fluid from the production well, separation and treatment of produced fluids, water injection and disposal, and transportation. The following conversion excludes CO_2 compression, which is accounted for in the CO_2 Compression and Transport Model Project description. In order to use this value for estimating electricity requirements, minimum and maximum injection rates in million standard cubic feet per day (MMscfd) are converted to minimum and maximum annual electricity requirements of 519 kilowatts (kW) and 11,826 kW, respectively.

2.5.5.3 Environmental Process Discharge Streams

Air emissions associated with equipment operations, land use, aesthetics, and noise related to project activities would occur over a short duration of time or be intermittent in nature. The use of distillate fuel for the heating unit is assumed to conservatively estimate the air emissions, which are detailed in Table 2-21.

Wastewater from CBM recovery wells may contain elevated levels of dissolved solids as well as organic and inorganic compounds. The wastewater could either be transferred to a storage tank for periodic off-site treatment and disposal or discharged under a National Pollutant Discharge Elimination System (NPDES) permit with limited treatment.

Well drilling cuttings would require collection and management. An estimated 873 cubic feet of cuttings collection would occur at each well. This estimate is based on an 8-inch diameter well with a maximum depth of 2,500 feet. Consistent with local regulatory regulations, soils that are contaminated with petroleum hydrocarbons or other drilling-related chemicals will be encapsulated on site or disposed in a permitted waste management facility.

2.5.5.4 Site Requirements and Operations

Detailed geologic and hydrogeologic information must be included in any model to accurately portray the potential environmental impacts of injecting CO_2 into the system. Because this is a hypothetical project, it is assumed that the site would have favorable hydrogeologic characteristics for this type of project:

- Faults and fractures present in the seam would have minor displacement.
- There would be limited CO_2 migration pathways between the coal seam and any potable water supply aquifer.
- The ratio of existing methane to water in the coal seam would be at least equal.
- The formation water in the coal seam would have sufficiently low dissolved constituent concentrations, thus requiring only limited treatment after its co-production with the CBM prior to its subsequent discharge.
- No methane or other gas would be liberated from outcrop areas of the coal seam as a result of groundwater level drawdown.

It is assumed that the model project would be co-located with a CO_2 source: therefore, a nearby pipeline would provide the necessary CO_2 for injection. Refer to Compression and Transport of Captured CO_2 Model Project description for additional information. The site should range from 90 to 1,500 acres.

A minimum and maximum distance between production and injection wells would be 1,000 feet and 1,800 feet, respectively (Reeves et al., 2002; NETL, 2002).

CBM production is anticipated to operate for one to three years prior to start up of CO_2 injection, and would continue to operate during injection. Note that in marginally gassy coal seams, there may be no initial CBM production; however CO_2 injection could be the catalyst to bring CBM production up to economic feasibility. CO_2 injection and CBM production would occur continuously with three shifts. It is anticipated that a smaller site would be automated, and one person would be required full time. For a larger acreage, potentially two people would work each shift. A small mobile trailer would be located on site for offices and sanitary facilities during construction and if needed, operation.

2.5.5.5 Construction Phase Activities

The site must be prepared prior to construction. Site preparation activities would include clearing of ground cover, development of access roads, and preparing the surface for drilling rigs and surface equipment. For 1,500 acres of land, a maximum of 13.6 miles of new dirt and/or gravel access roads are anticipated. Clearing would vary depending on the chosen site; however, a maximum clearing of 244 acres would be required for roads and equipment locations. This value is based on clearing 13.6 miles of access roads with a 75-foot right-of-way plus 3 acres for new well equipment locations. A crew of twelve equipped with appropriate machinery including front-end loaders and chippers would take about 15 days (1,440 man-hours) to prepare the site. For the 90 acre pilot scale site it is estimated a crew of three could prepare the site in 5 days.

Additional construction activities including equipment footers or pads, field erection of equipment, drilling of wells, piping, utility tie-ins (electricity), etc. would require a larger crew and heavy machinery. A crew of about 20 – 80 construction personnel would require between 3 – 9 months to complete these tasks.

Erosion control measures will be implemented during construction to ensure sediment generated from construction will be controlled from impacting stormwater runoff. These measures include sufficient temporary and permanent erosion control devices and practices to control erosion and retain sediment within the boundaries of the site.

Table 2-21. Sequestration of CO_2 - Coal Seam and CBM Model Project Data Sheet

Parameter	Minimum Value	Maximum Value	Basis of Data Assumption
Coal Seam Depth	1,000 feet	2,500 feet	UMWA
Coal Seam Thickness	10 feet	200 feet	Based on Allison Unit and URS geologic input
Coal Permeability	Medium	High	Low permeability would limit sequestration amount
Transport CO_2 to Site	Refer to Compression and Transport of Captured CO_2 Model Project Description		
Site Acreage	90	1,500	Based on the number of wells and the distance between
Clearing (acres)	19	244	Minimum and maximum based on 1 mile and 66 miles, respectively, of 75'-right-of-ways for new roads, plus 3 acres per new well for equipment locations.
Distance btw Wells	1,000 feet	1,800 feet	Based on CONSOL and Allison Projects
Injection Wells	1	12	Minimum based on Allison Project. All wells are new.
CBM Production Wells	2	20	Based on 3-spot and 5-spot patterns for 4 to 12 wells. All wells are new.
Observation/Monitoring Wells	1	8	Minimum based on CONSOL Project. All wells are new.
Access Roads (miles)	0.75	13.6	New roads for new wells.
CO_2 Distribution Piping (miles)	0.02	4.1	Based on the number of injection wells and the distance between. Assume 50% of piping exists in existing production right-of-ways. New piping will be placed in new road right-of-ways.
Total Average CO_2 Injected	35 tpd	2,750 tpd	Based on CONSOL and Allison projects, respectively
Total Average CO_2 Injected (MT/year)	11,590	910,600	Converted to Metric Tons and Multiplied tpd by 365
Wastewater Storage Capacity	500 gallons	10,000 gallons	(Reeves, 2002)
Wastewater Generation (gal/hr)	2.98	59.5	Assume storage capacity is a weekly quantity.
Personnel (Operations)	1 per shift	2 per shift	Minimum based on project being automated system
Air Emissions from Heater using Distillate Fuel			
Methane (CH_4) (lb/hr)	0.00007	0.006	AP-42, Section 1.3, Sept. 1998. Emission factor = 0.216 lb/1000 gal.
Nitrous Oxide (N_2O) (lb/hr)	0.00004	0.003	AP-42, Section 1.3, Sept. 1998. Emission factor = 0.11 lb/1000 gal.
Carbon Dioxide (CO_2) (lb/hr)	7.3	576.7	AP-42, Section 1.3, Sept. 1998. Emission factor = 22,300 lb/1000 gal.
Particulate Matter (PM) (lb/hr)	0.001	0.052	AP-42, Section 1.3, Sept. 1998. Emission factor = 2 lb/1000 gal.
Nitrogen Oxides (NO_f) (lb/hr)	0.007	0.517	AP-42, Section 1.3, Sept. 1998. Emission factor = 20 lb/1000 gal.
Carbon Monoxide (CO) (lb/hr)	0.002	0.129	AP-42, Section 1.3, Sept. 1998. Emission factor = 5 lb/1000 gal.
Volatile Organic Compounds (VOC) (lb/hr)	0.0002	0.014	AP-42, Section 1.3, Sept. 1998. Emission factor = 0.556 lb/1000 gal.
Distillate Fuel Usage (gal/yr)	2,884	226,560	Calculated from required energy of heating unit and based on 8,760 hours per year. (Total usage for injection wells.)
Well Drilling Cuttings	3,492 cu.ft.	34,920 cu.ft.	873 cu. ft. per well. Based on 8-inch diameter well with a maximum depth of 2,500 feet.

2.5.5.6 Underground Injection Regulations

CLASS II WELLS. Those wells are utilized for injection for the purpose of: a) enhanced recovery of oil and gas; b) injection for storage of hydrocarbons liquid, at standard temperature and pressure; and c) the disposal of fluids which are brought to the surface in connection with natural gas storage operations or conventional production of oil and gas. Produced water may be commingled with waste waters from gas plants that are an integral part of production operation, unless those waters are classified as a hazardous waste at the point of injection. This does not include waste fluids from CO_2 production plants.

Conditions for Operation:

- New injection wells require a Permit for construction or conversion.
- An existing hydrocarbon storage or enhanced recovery well may be authorized by rule for the life of the well.
- Permits are issued for a limited period of time, that may be up to the operating life of the facility.
- New injection wells must be tested for mechanical integrity prior to operation.
- Once in operation, injection wells must have a mechanical integrity test at least once every five years.
- Existing rule authorized injection wells, which have had the tubing disturbed (workover), must have a pressure test to demonstrate mechanical integrity.
- Injection pressure shall not exceed that which would initiate and/or propagate fractures in the confining zone adjacent to a USDW.
- A review of the Permit is required at least once every five years, including review of the most recent mechanical integrity test.
- Area Permits are allowed for wells within the same well field, project or formation operated by a single owner or operator.
- Area of review for newly permitted injection wells is a minimum of 1/4 mile radius. This radius will be greater if the radius of endangering influence is found to exceed the fixed radius.
- Authorization by rule is granted for existing enhanced recovery wells subject to applicable construction, operating, reporting, monitoring, plugging, and financial assurance requirements listed in 40 CFR 144.28. Successful mechanical integrity tests must be conducted at least once every five years30.
- Emergency Permits are allowed if they meet the stipulations of 40 CFR 144.34..
- Operator must conduct monitoring of injection pressure, flow rate, and volume. Continuous monitoring may, in specific situations, be required.

Monitoring Requirements:

- The operator must obtain a sample of the injection fluid and analyze it for specified parameters at least once within the first year of authorization, and thereafter when changes are made to the injection fluid.
- The operator shall observe the injection pressure, flow rate, and cumulative volume at least weekly for SWD wells; monthly for ER wells; and daily for HC and cyclic steam wells. At least one observation of each of the above parameters is to be recorded at intervals no greater than 30 days.
- The operator must perform a mechanical integrity test (MIT) on the well at least once every five (5) years during the life of the well, and following any workover operation.

Reporting Requirements:

- If a well is temporarily abandoned (TA), the operator must notify the UIC Director notification within 30 days. A well may remain TA for a period of two (2) years, after which the operator must plug and abandon the well unless an extension is requested and subsequently granted by the UIC Director. An extension will only be granted if the operator can demonstrate that no endangerment to USDWs will take place during the period of the TA.
- The operator must report any noncompliance with UIC regulations orally to EPA within 24 hours of discovery and in writing within five (5) days.
- Submit an Annual Disposal/Injection Well Monitoring Report (EPA Form 7520-11 or State equivalent) summarizing observations of injection pressure and cumulative volume. Submit the report to the UIC Director by January 31 of each year covering the observations for the previous year. This requirement may be different for permitted wells; refer to the permit for appropriate date and requirements.
- If a change of ownership occurs for rule-authorized wells, the operator must notify EPA within 30 days of such transfer. Permitted wells require 30 days notice in advance of the proposed transfer date. An Application to Transfer Permit (EPA Form 7520-7or State equivalent).
- Notify the UIC Director of company change of address at least 15 days prior to the effective date.
- Submit Well Rework Record (EPA Form 7520-12 or State equivalent) within 60 days of any well workover.
- Notify EPA at least 30 days prior to performing a mechanical integrity test (MIT). A shorter notice is permissible if sufficient time is allotted for EPA to witness the test. The operator must provide the UIC Director with test results within 30 days, unless a MIT failure occurs (pressure change of 10 percent or greater within 30 minutes), in which case notification must be within 5 days.
- Notify the UIC Director at least 45 days prior to initiating plugging and abandonment of a well. A shorter notice is permissible if sufficient time is allotted for the UIC Director to witness the operation.
- Submit a Plugging Record (EPA Form 7520-13 or State equivalent) within 60 days of plugging and abandonment of a well, specifying the manner in which the well was plugged.

Due to the increased use of lateral drilling to recover coalbed methane, some states are revising their field rules and permitting processes for coalbed methane wells. For example, some current rules may require notification of adjacent owners within a certain distance of a well head (surface location). Rules are changing to specify horizontal distance from any portion of the well, including laterals.

2.5.5.7 Best Management Practices for ECBM

In April 2002, DOE sponsored a "Handbook on Best Management Practices and Mitigation Strategies for Coal Bed Methane in the Montana Portion of the Powder River Basin" (DOE, 2002). Although this handbook is location-specific and does not pertain solely to enhanced coal bed methane recovery with injection of CO_2, many of the BMPs in this handbook could minimize environmental impacts associated with ECBM. A summary of general BMPs is provided below:

- Determine if a beneficial use of recovered groundwater can be applied (such as use in dust suppression, water for livestock, creation of fish ponds, or reinjection to recharge aquifers)
- Minimize construction of new roads and utility corridors by utilizing existing networks or placing new utilities and roads within the corridor.

- Use local terrain, noise reduction technology and camouflage to minimize impacts for both noise and visual impairments.
- Use electric and hydraulic motors to operate pumps and compressors to reduce air emissions. Use produced methane to power pumps since its combustion results in few emissions than diesel or gasoline.
- Properly re-vegetate disturbed areas, re-introducing impacted native species where necessary. Stockpile topsoil for use in reclamation of construction sites.
- Institute a visual monitoring program to identify and remove noxious weeds that may be introduced during the exploration through production phase.
- Plug dry holes and wells in accordance with BLM and/or state requirements (DOE, 2002).

2.5.6 Enhanced Oil Recovery Geologic Sequestration Model Project

These model projects were developed to evaluate the impacts of geologic sequestration in oil formations as a part of Enhanced Oil Recovery (EOR) operations. Two options are evaluated. The first option evaluates sequestration of CO_2, and the second evaluates co-sequestration of CO_2 and hydrogen sulfide (H_2S). These processes are also referred to as EOR flooding. The EOR formation sequestration model projects would consist of transporting the gas stream on site from a nearby source, heating and regulating the gas stream pressure as necessary, and injecting the gas stream into the oil formation.

CO_2 is miscible with oil, and, once dissolved, causes the oil to become less viscous and more mobile. Through EOR, an additional 5 to 20 percent of oil is recovered (Stevens, et. al., 2000).

The following sections, which describe the model project, include the following elements:

- General design and operating parameters, including Monitoring, Mitigation, and Verification (MM&V);
- Utility requirements;
- Environmental process discharge streams;
- Site requirements and operations; and
- Construction phase activities.

2.5.6.1 Case A – Sequestration of CO_2

The first CO_2 flood occurred in 1972 in Texas, and since has grown into a widely-used practice nationwide and around the world to enhance the recovery of oil. Over 70 CO_2-EOR projects are currently active in the U.S.. Therefore, the technology to operate EOR formation CO_2 sequestration projects has been well developed. These projects have all operated with appropriate permits and approvals, as applicable by their respective states, including completing the NEPA review process and acquiring environmental permits, such as an air quality permit.

2.5.6.1.1 General Design and Operating Parameters

Favorable project conditions have been narrowed to a range of values to provide flexibility of project placement. These ranges have been derived from review of a few existing projects of CO_2 injection into oil formations. Six of the many existing commercial-sized projects were reviewed for this model project. These six are the Weyburn Field Project (Weyburn) in the Williston Basin oilfield in Weyburn, Saskatchewan; the Rangely Weber Field Project (Rangely) in Colorado; the Scurry Area Canyon Reef Operators Committee (SACROC) Field Project in the Permian Basin in Texas; the Wasson Denver Field Project in the Permian Basin in Texas; the PetroSource Energy field in Texas (PetroSource) which is owned by Riata Energy; and Denbury Resources Little Creek field in Mississippi (Denbury).

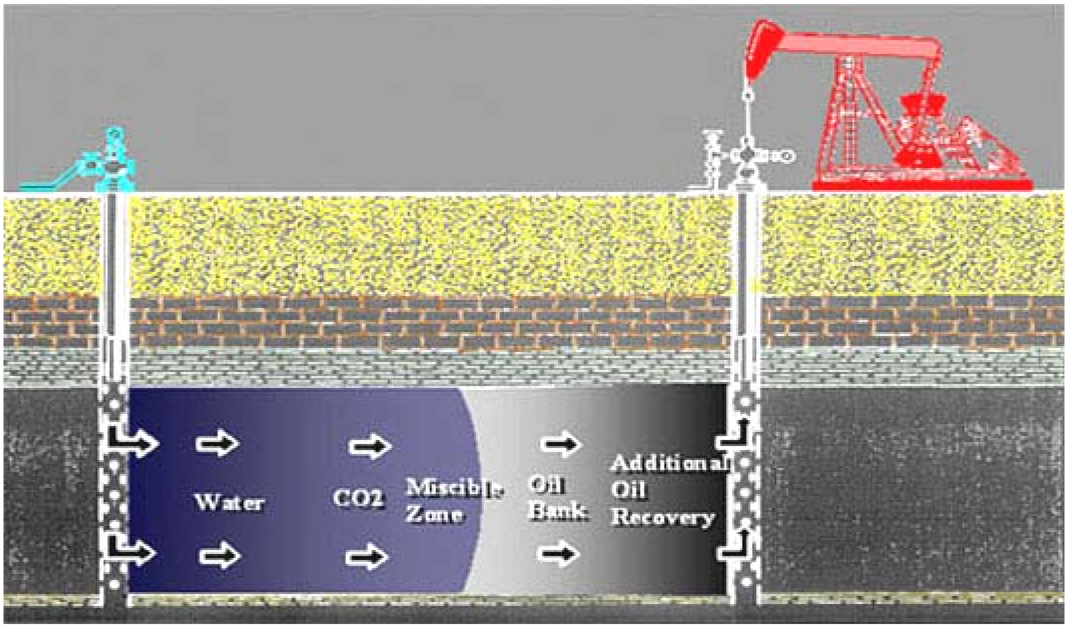
Descriptions of the model project parameters are included in Table 2-22. CO_2 injection at Weyburn averages 120 million standard cubic feet per day (MMscfd), 21 percent of which was recycled back from the production wells. Some of the CO_2 injected for EOR purposes is co-produced as associated gas or entrained with the oil. Because the CO_2 has a significant delivery cost, and incremental value to EOR operations, most CO_2 injection EOR operations include gas capture/recovery, separation, and reinjection of the CO_2 as a “recycle” stream.

CO_2 injection at Rangely peaked at 180 MMscfd and now operates at 60 MMscfd. SACROC also maintains an average injection rate of 60 MMscfd. Wasson Denver’s CO_2 current injection rate is 320MMscfd (down from it previous 10-year long-term injection level of 426 MMscfd). CO_2 injection at PetroSource averages 37 MMscfd. Denbury maintains an average injection rate of 142 MMscfd. To ensure the model project encompasses injection rates similar to the commercial projects, the following range of CO_2 daily average injection rates were used: 1.17 MMscfd as a minimum from one well and 42.1 MMscfd as a maximum from thirty-six wells. These minimum and maximum rates are based on Wasson Denver injectivity rates (per injection well). For EOR operations, CO_2 is injected in its minimum supercritical state [greater than 1087 psi (6.9 MPa) and 88^{o}F (31^{o}C)] (EPRI, 1999).

For a field validation project, or a potentially larger pilot project, the number of injection wells would range from 1 to 36, the minimum of which is based on the average of the five smallest U.S. CO_2 EOR field projects (EPRI, 1999). The maximum is based on PetroSource. All injection wells would be new construction. The majority of other project data (site acreage, miles of access roads, etc.) is based on the number of injection wells. Between 2 and 115 production wells would be used for oil production. Six wells for the minimum case are assumed to be existing wells, and of the 115 wells in the maximum case, at least half (or 58 wells) are assumed to be existing, with the remaining maximum of 57 being new construction. Between 1 and 20 new monitoring wells would be used for various MM&V requirements. The maximum number of production wells is based on the ratio of production to injection wells for the Rangely, Weyburn, and SACROC projects, with the minimum based on small U.S. CO_2 EOR projects. The number of monitoring wells is also estimated based on the Rangely, Weyburn, and SACROC projects. If multiple wells are drilled, they would typically be at various depths. These wells would monitor the stability of the sequestered CO_2 injected in the oil formation, as well as other hydrogeologic parameters that may indicate undesirable leakage of fluids from the formation. Figure 2-10 illustrates the typical configuration of CO_2 flooding using injection and production wells.

Depending on the depth of the oil formation, wells may extend from approximately 2,000 feet to 7,000 feet in depth. The ranges for the well depths are based on information from the Petroleum Technology Transfer Council website (www.pttc.org) and the CO_2 Norway website (www.co2.no).

A range of 0.5 mile to 11 miles of new 4-inch piping would be required to distribute the CO_2 to individual wells on site. This maximum of 11 miles is assuming the distribution lines would begin at one central location and distribute out to three main distribution lines which would feed to the individual injection wells. It is assumed that 50 percent of needed piping exists in existing production right-of-ways. New piping would be placed in new road right-of-ways. Injection wells are a maximum of 1,600 feet apart. This piping would be buried to ensure that seasonal temperatures do not affect line pressures, and thus injection rates. This dispersion system would connect to individual well sites via a 2-inch pipe.



Source: CO_2 Norway, 2007.

Figure 2-10. CO_2 Flooding

The types of surface equipment for CO_2 injection anticipated for the model project are discussed in the following paragraphs. The surface configuration for a CO_2 injection well would consist of the following equipment (EPRI, 1999). The Compression and Transport of Captured CO_2 Model Project Description compresses the gas stream to 3,000 psia. A pump, potentially a booster pump, would regulate the injection pressure and flow rate. A water injection pump will likely be required as well (Figure 2-11). A pipeline of recycled CO_2 from the production wells would also connect to the compressor or injection well.

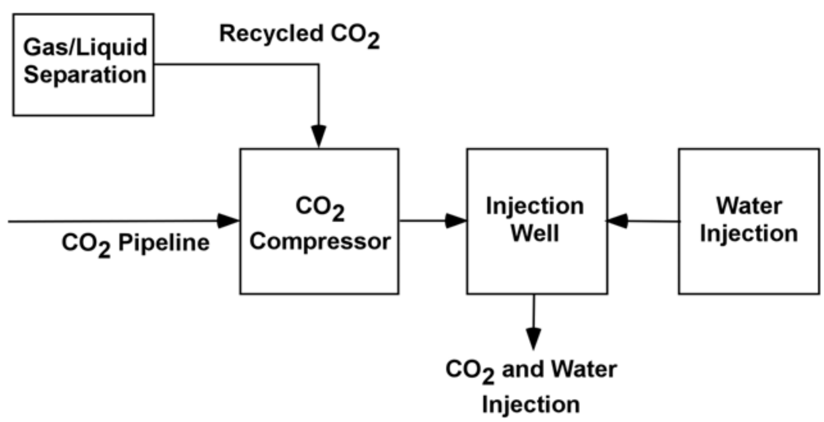


Figure 2-11. CO_2 Injection Well EOR Surface Configuration

For a model project with the maximum number of injection and production wells, the surface configuration for an oil production well would consist of the well and a multiphase pump to move multiphase mixtures to a centralized production facility. This facility would separate CO_2, oil and water, and distribute the non-petroleum liquids for recirculation or to storage tanks. For a minimum size model project, the production well site would potentially also contain smaller separation, gas compression, and tank storage capacities, rather than a centralized production facility. A water disposal well would also be required to pump separated water back into the ground (EPRI, 1999).

Prior to injection, various methods of MM&V can be conducted to form a data baseline of the oil formation, groundwater formations, surface water, and gas monitoring. These technologies are then continued during injection, and for extensive time periods following injection. Monitoring during and after injection would also include produced fluids (oil and water), produced gas (natural gas, condensable hydrocarbons, CO_2), soil gas sampling, geophysical measurements, and well logs.

2.5.6.1.2 Utility Requirements

Electricity will be required to operate multiple site operations. The major power demand operations include pumping fluid from the production well, separation and treatment of produced fluids, water injection and disposal, and transportation. Total electric power capacity for CO_2-EOR operations in the U.S. is estimated at about 963,000 horsepower (hp) or 788 megawatts (MW) (EPRI, 1999). Based on total U.S. 2000 CO_2 flooding volumes of 30 million tons / year (Stevens et al., 2000), annual electricity usage rates for CO_2 EOR operations is estimated at 1.86 hp / MMscf or 1.387 KW/MMscf.

2.5.6.1.3 Environmental Process Discharge Streams

Air emissions associated with equipment operations, land use, aesthetics, and noise related to project activities would occur over a short duration of time or be intermittent in nature. For example, if the compressor used either natural gas or diesel fuel for operations, minor quantities of hazardous air pollutants and criteria pollutants such as nitrogen oxides and carbon monoxide would be emitted. Refer to the CO_2 Compression and Transport Model Project description for additional information regarding environmental concerns.

Once the produced fluids (oil and water) are separated, the non-potable water will require disposal. Typically, an underground injection well at the project site is used to dispose of the non-potable, saline produced water.

Another potential concern is subsurface leakage of the formation fluids. Well leakage can be caused by inadequate annular seals or damaged casing in the production or injection wells. Leakage of saline water or gas from the subsurface formation can result from higher injection pressures, either by hydrofracturing or by fluids bypassing the petroleum "trap", which created the formation.

Well drilling cuttings would require collection and management. An estimated maximum 2,400 cubic feet of cuttings collection would occur at each new well. This estimate is based on an 8-inch diameter well with a maximum depth of 7,000 feet. Consistent with local regulatory regulations, soils that are contaminated with petroleum hydrocarbons or other drilling-related chemicals will be encapsulated on site or disposed in a permitted waste management facility.

2.5.6.1.4 Site Requirements and Operations

It is assumed that the full-scale, commercial size model project would either be co-located with a CO_2 source, or would be located in an area relatively proximate (e.g. 10-20 miles) to a nearby major CO_2 source and/or existing CO_2 pipeline. Therefore, a nearby pipeline would provide the CO_2 for injection for the commercial-scale project. Truck (or rail) transport is assumed for the small-scale, field validation R&D project. Refer to Compression and Transport of Captured CO_2 Model Project Description for additional information. The site should range from 135 to 2,880 acres. A minimum distance between injection and production wells would be 500 feet and the maximum distance between injection wells would be 1,600 feet. The maximum distance is based on the Rangely Weber and Wasson Denver projects.

CO_2 injection would occur continuously with three shifts. Monitoring is anticipated to operate prior to, during and following completion of CO_2 injection. It is anticipated that a smaller site would be automated and only one person would be required full time. For a larger acreage, potentially three people would work each shift. A small mobile trailer would be located on site for offices and sanitary facilities during construction, and operation.

2.5.6.1.5 Construction Phase Activities

The site must be prepared prior to construction. Site preparation activities would include clearing of ground cover, development of access roads, and preparing the surface for drilling rigs and surface equipment. For a site maximum area of 2,880 acres of land, a maximum of 43 miles of new dirt and/or gravel access roads are anticipated. Clearing would vary depending on the chosen site; however, a maximum clearing of 686 acres would be required for roads and equipment locations. This value is based on clearing 43 miles of access roads with a 75-foot right-of-way plus 3 acres for new well equipment locations. A crew of nineteen equipped with appropriate machinery including front-end loaders and chippers would take about 30 days (4600 man-hours) to prepare the site. The pilot scale facility would require approximately 135 acres of land, 15 of which would be cleared, and 1 mile of access roads.

Additional construction activities including equipment footers or pads, field erection of equipment, drilling of wells, piping, utility tie-ins (electricity), etc. would require a larger crew and heavy machinery. A crew of approximately 20 to 50 construction personnel would require between 3 to 9 months to complete these tasks.

Erosion control measures will be implemented during construction to ensure sediment generated from construction will be controlled from impacting stormwater runoff. These measures include sufficient temporary and permanent erosion control devices and practices to control erosion and retain sediment within the boundaries of the site.

2.5.6.2 Case B – Co-Sequestration of Sour Gas (CO_2 and H_2S)

2.5.6.2.1 General Design and Operating Parameters

To ensure the model project encompasses injection rates similar to the commercial projects, the following range of CO_2 daily average injection rates were used: 1.17 MMscfd as a minimum from one well and 42 MMscfd as a maximum from thirty-six wells. These minimum and maximum rates are based on Rangely and SACROC. For EOR operations, CO_2 is injected in its minimum supercritical state [greater than 1087 psi (6.9 MPa) and 88^{o}F (31^{o}C)] (EPRI, 1999). Based on the Gas Research Institute Topical Report (GRI, 1991), the maximum weight percent (wt %) of H_2S in the gas stream would be 25. The minimum would be 2 wt%.

For a field validation project, or a potentially larger pilot project, the number of injection wells would range from 1 to 36, the same as that of Case A: Sequestration of CO_2 EOR. All injection wells would be new construction. The majority of other project data (site acreage, miles of access roads, etc.) is based on the number of injection wells. Between 6 and 115 production wells would be used for oil production. Two wells for the minimum case are assumed to be existing wells, and of the 115 wells in the maximum case, at least half (or 58 wells) are assumed to be existing, with the remaining maximum of 57 being new construction. Between 1 and 20 monitoring wells would be used for various MM&V requirements. The number of production wells is based on the ratio of production to injection wells for the Rangely, Weyburn, and SACROC projects. The number of monitoring wells is also estimated based on the Rangely, Weyburn, and SACROC projects. If multiple wells are drilled, they would typically be at various depths. These wells would monitor the stability of the sequestered CO_2 injected in the oil formation, as well as other hydrogeologic parameters that may indicate undesirable leakage of fluids from the formation.

Depending on the depth of the oil formation, wells may extend from approximately 2,000 feet to 7,000 feet in depth. The ranges for the well depths are based on information from the Petroleum Technology Transfer Council website (www.pttc.org) and the CO_2 Norway website (www.co2.no).

A range of 0.5 mile to 11 miles of 4-inch piping would be required to transport the CO_2 to individual wells on site. This maximum of 11 miles is assuming the distribution lines would begin at one central location and distribute out to three main distribution lines which would feed to the individual injection wells. It is assumed that 50 percent of needed piping exists in existing production right-of-ways. New piping would be placed in new road right-of-ways. As discussed later, injection wells are a maximum of 1,600 feet apart. This piping would be buried to ensure that seasonal temperatures do not affect line pressures, and thus injection rates. This dispersion system would connect to individual well sites via a 2-inch pipe.

The types of surface equipment for CO_2 injection anticipated for the model project are discussed in the following paragraphs. The surface configuration for a CO_2 injection well would consist of the following equipment (EPRI, 1999). The Compression and Transport of Captured CO_2 Model Project Description compresses the gas stream to 3,000 psia. A pump, potentially a booster pump, would regulate the injection pressure and flow rate. A water injection pump will likely be required as well. A pipeline of recycled CO_2 from the production wells would also connect to the compressor or injection well.

For a model project with the maximum number of injection and production wells, the surface configuration for an oil production well would consist of the well and a multiphase pump to move multiphase mixtures to a centralized production facility. This facility would separate CO_2, oil and water, and distribute the non-petroleum liquids for recirculation or to storage tanks. For a minimum size model project, the production well site would potentially also contain smaller separation, gas compression, and tank storage capacities, rather than a centralized production facility. A water disposal well would also be required to pump separated water back into the ground (EPRI, 1999).

Prior to injection, various methods of MM&V can be conducted to form a data baseline of the oil formation, groundwater formations, surface water, and gas monitoring. These technologies are then continued during injection, and for extensive time periods following injection. Monitoring during and after injection would also include produced fluids (oil and water), produced gas (natural gas, condensable hydrocarbons, and CO_2), and soil gas sampling.

2.5.6.2.2 Utility Requirements

Electricity will be required to operate multiple site operations. The major power demand operations include pumping fluid from the production well, separation and treatment of produced fluids, water injection and disposal, and transportation. Total electric power capacity for CO_2-EOR operations in the U.S. is estimated at about 963,000 horsepower (hp) or 788 megawatts (MW) (EPRI, 1999). Based on total U.S. 2000 CO_2 flooding volumes of 30 million tons / year (Stevens et al., 2000), annual electricity usage rates for CO_2 EOR operations is estimated at 1.86 hp / MMscf.

2.5.6.2.3 Environmental Process Discharge Streams

Air emissions associated with equipment operations, land use, aesthetics, and noise related to project activities would occur over a short duration of time or be intermittent in nature. For example, if the compressor used either natural gas or diesel fuel for operations, minor quantities of hazardous air pollutants and criteria pollutants such as nitrogen oxides and carbon monoxide would be emitted. Refer to the CO_2 Compression and Transport Model Project description for additional information regarding environmental concerns.

Once the produced fluids (oil and water) are separated, the non-potable water will require disposal. Typically, an underground injection well at the project site is used to dispose of the non-potable, saline produced water.

Another potential concern is subsurface leakage of the formation fluids. Well leakage can be caused by inadequate annular seals or damaged casing in the production or injection wells. Leakage of saline water or gas from the subsurface formation can result from higher injection pressures, either by hydrofracturing or by fluids bypassing the petroleum "trap", which created the formation.

Well drilling cuttings would require collection and management. An estimated maximum 2,400 cubic feet of cuttings collection would occur at each new well. This estimate is based on an 8-inch diameter well with a maximum depth of 7,000 feet. Consistent with local regulatory regulations, soils that are contaminated with petroleum hydrocarbons or other drilling-related chemicals will be encapsulated on site or disposed in a permitted waste management facility.

2.5.6.2.4 Site Requirements and Operations

It is assumed that the full-scale, commercial size model project would either be co-located with a CO_2 source, or would be located in an area relatively proximate (e.g. 10-20 miles) to a nearby major CO_2 source and/or existing CO_2 pipeline. Therefore, a nearby pipeline would provide the CO_2 for injection for the commercial-scale project. Truck (or rail) transport is assumed for the small-scale, field validation R&D project. Refer to Compression and Transport of Captured CO_2 Model Project Description for additional information. The site should range from 135 to 2,880 acres. A minimum distance between injection and production wells would be 500 feet and the maximum distance between injection wells would be 1,600 feet. The maximum distance is based on the Rangely Weber and Wasson Denver projects.

CO_2 injection would occur continuously with three shifts. Monitoring is anticipated to operate prior to, during and following completion of CO_2 injection. It is anticipated that a smaller site would be automated and only one person would be required full time. For a larger acreage, potentially three people would work each shift. A small mobile trailer would be located on site for offices and sanitary facilities during construction, and operation.

2.5.6.2.5 Construction Phase Activities

The site must be prepared prior to construction. Site preparation activities would include clearing of ground cover, development of access roads, and preparing the surface for drilling rigs and surface equipment. For a site maximum area of 2,880 acres of land, a maximum of 43 miles of dirt and/or gravel access roads are anticipated. Clearing would vary depending on the chosen site; however, a maximum clearing of 686 acres would be required for roads and equipment locations. This value is based on clearing 43 miles of access roads with a 75-foot right-of-way plus 3 acres for new well equipment locations. A crew of nineteen equipped with appropriate machinery including front-end loaders and chippers would take about 30 days (4600 man-hours) to prepare the site.

Additional construction activities including equipment footers or pads, field erection of equipment, drilling of wells, piping, utility tie-ins (electricity), etc. would require a larger crew and heavy machinery. A crew of approximately 20 to 50 construction personnel would require between 3 to 9 months to complete these tasks.

Erosion control measures will be implemented during construction to ensure sediment generated from construction will be controlled from impacting stormwater runoff. These measures include sufficient temporary and permanent erosion control devices and practices to control erosion and retain sediment within the boundaries of the site.

Table 2-22. Case A - Sequestration of CO_2 - EOR Model Project Data Sheet.

Parameter	Minimum Value	Maximum Value	Basis of Data Assumption
Oil Formation Depth	2,000 feet	7,000 feet	Based on CO_2 Norway and PTTC websites
Transport CO_2 to Site	Refer to Compression and Transport of Captured CO_2 Model Project Description		
Site Acreage	135	2,880	Based on the number of wells and the distance between
Distance btw Wells	500 feet	1,600 feet	Maximum based on injection well to production well spacing; maximum based on average of Rangely Weber and Wasson Denver injection well to injection well spacing.
Injection Wells	1-2	36	Minimum based on average of 5 smallest U.S. CO2 EOR field projects. Maximum based on PetroSource. All wells are new.
Production Wells	6	115	Based on the ratio of production to injection wells for Weyburn, Rangely and SACROC. For minimum, wells are existing. For maximum, 50% (58 wells) are existing.
Observation / Monitoring Wells	1	20	Based on Weyburn, Rangely and SACROC projects. All wells are new.
Clearing (acres)	15	686	Minimum and maximum based on 1 mile and 43 miles, respectively, of 75'-right-of-ways for new roads, plus 3 acres per new well for equipment locations.
New Access Roads (miles)	1	43	New roads for new wells.
New CO_2 Distribution Piping to Injection (miles)	0.5	11	Based on the number of injection wells and the distance between. Assume 50% of piping exists in existing production right-of-ways. New piping will be placed in new road right-of-ways.
Total Average CO_2 Injected	1.17 MMscfd	42.1 MMscfd for 36 wells	Based on Wasson Denver long-term injectivity.
Total Average CO_2 Injected (MT/year)	22,498	809,209	Converted MMscfd to MT/year using Ideal Gas Law
Personnel (Operations)	1 per shift	3 per shift	Minimum based on model project being automated system
Well Drilling Cuttings	4,800 cu.ft	268,800 cu.ft	Based on 8-inch diameter well with a maximum depth of 7,000 feet.
Utility Requirements	0.32 kW	65.2 kW	Based on 1.86 hp / MMscf = 1.387 kW / MMscf

Table 2-23. Case B - Sequestration of CO_2/H_2S EOR Model Project Data Sheet.

Parameter	Minimum Value	Maximum Value	Basis of Data Assumption
Oil Formation Depth	2,000 feet	7,000 feet	Based on CO_2 Norway and PTTC websites
Transport CO_2 to Site	Refer to Compression and Transport of Captured CO_2 Model Project Description		
Site Acreage	135	2,880	Based on the number of wells and the distance between
Distance btw Wells	500 feet	1,600 feet	Maximum based on injection well to production well spacing; maximum based on average of Rangely Weber and Wasson Denver injection well to injection well spacing.
Injection Wells	1	36	Minimum based on average of 5 smallest U.S. CO2 EOR field projects. Maximum based on PetroSource. All wells are new.
Production Wells	6	115	Based on the ratio of production to injection wells for Weyburn, Rangely and SACROC. For minimum, wells are existing. For maximum, 50% (58 wells) are existing.
Observation / Monitoring Wells	1	20	Based on Weyburn, Rangely and SACROC projects. All wells are new.
Clearing (acres)	15	686	Minimum and maximum based on 1 mile and 43 miles, respectively, of 75'-right-of-ways for new roads, plus 3 acres per new well (equipment locations).
New Access Roads (miles)	1	43	New roads for new wells.
New CO_2 Distribution Piping to Injection (miles)	0.5	11	Based on the number of injection wells and the distance between. Assume 50% of piping exists in existing production right-of-ways. New piping will be placed in new road right-of-ways.
Total Average Sour Gas Injected	1.17 MMscfd	42.1 MMscfd for 36 wells	Based on Wasson Denver long-term injectivity.
Total Average Sour Gas Injected (MT/year)	22,498 tpy	809,209	Converted MMscfd to MT/year using Ideal Gas Law
CO_2 Injected (MT/year)	22,048	606,907	Based on minimum of 75 wt% and maximum of 98 wt%.
H_2S Injected (MT/year)	450	202,302	Based on minimum of 2 wt% and maximum of 25 wt%. Maximum wt% based on Gas Research Institute Topical Report (GRI, 1991).
Personnel (Operations)	1 per shift	3 per shift	Minimum based on model project being automated system
Well Drilling Cuttings	4,800 cu.ft	268,800 cu.ft	Based on 8-inch diameter well with a maximum depth of 7,000 feet.
Utility Requirements	1.62 kW	58.3 kW	Based on 1.86 hp / MMscf = 1.387 kW / MMscf

2.5.7 Saline Formation Geologic Sequestration Model Projects

These model projects were developed to evaluate the impacts of geologic sequestration in saline formations. Two options are evaluated. The first option evaluates sequestration of CO_2, and the second evaluates co-sequestration of sour associated gas, CO_2 and hydrogen sulfide (H_2S). The saline formation sequestration model projects would consist of transporting the gas stream on site from a nearby source, heating and regulating the pressure of the gas stream, and injecting the gas stream into the saline formation.

The following sections, which describe the model projects, include the following elements:

- General design and operating parameters including Monitoring, Mitigation, and Verification (MM&V),
- Utility requirements,
- Environmental process discharge streams,
- Site requirements and operations, and
- Construction phase activities.

2.5.7.1 Case A – Sequestration of CO_2

The technology to operate saline formation CO_2 sequestration projects are currently in practice. CO_2 sequestration projects in saline formations have occurred in various locations worldwide. Within the U.S., CO_2 sequestration occurred in the Frio sandstone formation in Texas. Worldwide, CO_2 sequestration occurred in the South Nagaoka Gas Field in Nagaoka, Japan, and in the Sleipner Gas Field in the Norwegian North Sea. These projects have all operated with appropriate permits and approvals, as applicable by their respective countries. For example, the Frio project in Texas completed the NEPA review process and acquired environmental permits, such as an air quality permit.

2.5.7.1.1 General Design and Operating Parameters

Favorable project conditions have been narrowed to a range of values to provide flexibility of project placement. These ranges have been derived from review of existing projects of CO_2 injection into saline formations. The three existing projects that were reviewed are the Frio Brine Pilot Project (Frio) in the Frio sandstone formation in Texas, the Sleipner Gas Field (Sleipner) in the Norwegian North Sea, and the South Nagaoka Gas Field (Nagaoka) in Nagaoka, Japan. The Frio and Nagaoka projects are onshore, small-scale pilot R&D size projects, while Sleipner is an off-short, full-scale commercial sized project.

Typical model project parameters are summarized in Table 2-24. CO_2 injection at Nagaoka averaged from 20 tons/day to 40 tons/day between July 2003 and November 2004. CO_2 injection at Frio averaged at 178 tons/day over the nine day injection period in October 2004. Sleipner, a full scale project, began CO_2 injection in October 1996 and continues to maintain an average daily injection rate of 2,800 tons of CO_2 to date (Statoil, 2004). To ensure the model project encompasses injection rates similar to a commercial project, the following range of CO_2 daily injection rates would be used: 40 tons/day (13,140 MT/year) as a minimum from one well for a pilot-scale, R&D sized project and 2,800 tons/day (927,100 MT/year) as a maximum from three wells for a full-scale, commercial size project (Note: As a point of comparison, a typical 200 MW coal-fired power plant has CO_2 emissions on the order of 4,000 tons/day).

The number of injection wells would range from 1 to 20, of which the minimum number is based on both the on-shore pilot projects and the injection rate based on Nagaoka. In part because of its off-short location and well requirements, Sleipner has only a single injection well. Therefore, for the maximum number of wells for a commercial-scale on-shore saline formation project, it was assumed that the injectivity of a saline formation would be roughly twice that of an EOR formation or 2.34

MMscfd/injector. At 2740 tons per day or 47.2 MMscfd total CO_2 injection, this results in a maximum of 20 injection wells.

Table 2-24. Case A - Sequestration of CO_2 - Saline Formation Model Project Data Sheet.

Parameter	Minimum Value	Maximum Value	Basis of Data Assumption
Saline Formation Depth	3,000 feet	6,000 feet	Based on Frio, Nagaoka, and Sleipner Projects
Saline Formation Thickness	160 feet	1,000 feet	Based on Frio, Nagaoka, and Sleipner Projects
Transport CO_2 to Site	Refer to Compression and Transport of Captured CO_2 Model Project Description		
Site Acreage	92	2,750	Based on the number of wells and the distance between
Distance btw Wells	500 feet	2000 feet	Minimum based on Frio and Nagaoka projects. Maximum based on extrapolation of Sleipner projections.
Injection Wells	1	20	Based on Frio, Nagaoka, and Sleipner Projects for minimum. Maximum based on twice the EOR injectivity. Wells are new.
Observation / Monitoring Wells	1	8	Based on minimum of 1, but potentially 8 for larger acreage. Wells are new.
Well Drilling Cuttings	4,200 cu.ft.	58,800 cu.ft.	Based on 8-inch diameter well with a maximum depth of 6,000 feet.
Clearing (acres)	9	291	Maximum based on 23 miles of 75'-right-of-ways for new roads, plus 3 acres per new well for equipment locations.
New Access Roads (miles)	0.3	23	New roads for new wells.
New CO_2 Distribution Piping to Injection (miles)	0.1	7.6	Maximum based on 3 distribution lines from central point between injection wells with minimum distances of 500 feet and 2000 feet respectively. All new piping, which will be placed in new road right-of-ways.
Total Average CO_2 Injected (MT/day)	36	2,490	Based on Nagaoka and Sleipner Projects, respectively
Total Average CO_2 Injected (MT/year)	13,140	909,100	Multiplied by 365
Personnel (Operations)	1 per shift	2 per shift	Minimum based on model project being an automated system
Distillate Fuel Usage	3,295 gal/yr	76,893 gal/yr	Calculated from required energy of heating unit and based on 8,760 hours per year.
Air Emissions from Heater using Distillate Fuel			
Methane (CH_4) (lb/hr)	0.00008	0.002	AP-42, Section 1.3, September 1998. Emission factor = 0.216 lb/1000 gal.
Nitrous Oxide (N_2O) (lb/hr)	0.00004	0.001	AP-42, Section 1.3, September 1998. Emission factor = 0.11 lb/1000 gal.
Carbon Dioxide (CO_2) (lb/hr)	8.4	195.7	AP-42, Section 1.3, September 1998. Emission factor = 22,300 lb/1000 gal.
Particulate Matter (PM) (lb/hr)	0.001	0.018	AP-42, Section 1.3, September 1998. Minimum emission factor (2 lb/1000 gal) is for Boilers <1 MMBtu/hr, maximum emission factor (2 lb/1000 gal) for Boilers >1 MMBtu/hr.
Nitrogen Oxides (NO_f) (lb/hr)	0.008	0.211	AP-42, Section 1.3, September 1998. Minimum emission factor (20 lb/1000 gal) is for Boilers <1 MMBtu/hr, maximum emission factor (24 lb/1000 gal) for Boilers >1 MMBtu/hr.
Carbon Monoxide (CO) (lb/hr)	0.002	0.044	AP-42, Section 1.3, September 1998. Minimum emission factor (5 lb/1000 gal) is for Boilers <1 MMBtu/hr, maximum emission factor (5 lb/1000 gal) for Boilers >1 MMBtu/hr.
Volatile Organic Compounds (VOC) (lb/hr)	0.0002	0.005	AP-42, Section 1.3, September 1998. Emission factor = 0.556 lb/1000 gal.

The majority of other project data (site acreage, miles of access roads, etc.) is based on the number of injection wells. Between 1 and 8 monitoring wells would be installed for various MM&V requirements. If multiple wells are drilled, they would typically be at various depths. These wells would monitor the stability of the sequestered CO_2 injected in the saline formations. All injection and monitoring wells would be new construction.

Depending on the depth of the saline formation, wells may extend from 3,000 to 6,000 feet in depth, with the formation ranging from 160 feet to 1,000 feet thick. The ranges for the well depths and the saline formation thickness used in the model projects are based on all three existing field projects (Note: Some of the Regional Partnerships are in the process of evaluating potential sequestration opportunities at even greater depths, i.e., up to 10,000 feet or deeper).

A range of 0.1 mile to 7.6 miles of 4-inch piping would be required to distribute the CO_2 to individual wells on site. This maximum of 7.6 miles is assuming the distribution lines would begin near a location central to the twenty injection wells and distribute out to each injection well. As discussed later, injection wells are a minimum of 500 feet from any observation well or injection well. This piping would be buried to ensure that seasonal temperatures do not affect line pressures, and thus injection rates. This dispersion system would connect to individual well sites via a 2-inch pipe. All piping would be new construction.

The types of surface equipment for CO_2 injection anticipated for the model project are discussed in the following paragraphs. The surface configuration for a CO_2 injection well would consist of the following equipment (Hovorka et al., 2003; Kikuta et al., 2004). At least one main pump, and potentially a booster pump would regulate the injection pressure and flow rate. A heating unit would be anticipated as the CO_2 would require temperature control. The heating unit would either use natural gas, diesel fuel, or electricity for operations. Inline monitors will ensure the CO_2 is injected at the appropriate temperature. A Supervisory Control and Data Acquisition (SCADA) system may be used to monitor and transmit flow rate, pressure, and temperature information to a central data collection point. The SCADA system would be solar powered with a battery backup.

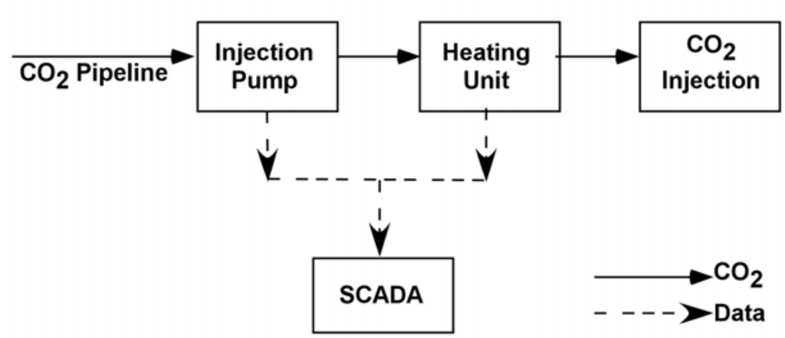


Figure 2-12. CO_2 Injection Well Saline Formation Surface Configuration.

Figure 2-12 shows the flow diagram of the surface configuration.

Prior to injection, various methods of MM&V can be conducted to form a data baseline of the saline formation, groundwater formations, surface water, and gas monitoring. These technologies are then continued during injection, and for extensive time periods following injection. MM&V technologies may include seismic tomography and monitoring, wireline logging, measurement of in-situ temperature and pressure, and electromagnetic imaging (Kikuta et al., 2004; Techline, 2004).

2.5.7.1.2 Utility Requirements

Utility requirements for the model project include fuel usage and electricity. Fuel would be trucked on site for the injection well heating unit. No additional on-site fuel storage is anticipated. Fuel usage would range from approximately 3,295 gallons per year to 76,893 gallons per year for the minimum and maximum scenarios. Electricity would be required to operate the injection pumps and potentially the heating unit.

2.5.7.1.3 Environmental Process Discharge Streams

Air emissions associated with equipment operations, land use, aesthetics, and noise related to project activities would occur over a short duration of time or be intermittent in nature. Usage of distillate fuel is assumed for a conservative estimate of air emissions.

Table 2-24 shows air emissions for the minimum and maximum scenarios. Refer to the CO_2 Compression and Transport Model Project description for additional information regarding environmental concerns.

Another potential concern is subsurface leakage of the formation fluids. Well leakage can be caused by inadequate annular seals or damaged casing in the production or injection wells. Leakage of saline water or gas from the subsurface formation can result from higher injection pressures, either by hydrofracturing or by fluids bypassing the caprock seal.

Well drilling cuttings would require collection and management. An estimated maximum 2,100 cubic feet of cuttings collection would occur at each well. This estimate is based on an 8-inch diameter well with a maximum depth of 6,000 feet. Consistent with local regulatory regulations, soils that are contaminated with petroleum hydrocarbons or other drilling-related chemicals will be encapsulated on site or disposed in a permitted waste management facility.

2.5.7.1.4 Site Requirements and Operations

It is assumed that the full-scale, commercial sized model project would be co-located with a CO_2 source and/or existing CO_2 pipeline. Therefore, a nearby pipeline would provide the necessary CO_2 for injection for the commercial-scale project. Truck (or rail) transport is assumed for the small-scale field validation R&D project. Refer to the Compression and Transport of Captured CO_2 Model Project Description for additional information. The site should range from 92 to 2,750 acres. A minimum distance between injection and observation wells would be 500 feet (NETL, 2003; Kikuta et al., 2004). Depending on the formation properties, injection wells could be up to 2500 feet apart from each other (Myer, 2005).

For Sleipner's 2,740 tons per day single CO_2 injector, pre-injection modeling indicated CO_2 movement of 10,000 feet from the injection point in 20 years; 3-year post-injection measurements indicated a 3,500 by 5,000 foot CO_2 bubble, with structural trap containment after 20 years projected at a maximum of 40,000 feet from the injection point (Statoil, 2004). For this onshore model project's 20 CO_2 injectors, each with 5 percent of the Sleipner injection rate, a 2,000 foot injection well to injection well spacing was assumed.

CO_2 injection would occur continuously with three shifts. Monitoring is anticipated to operate prior to, during and following completion of CO_2 injection. It is anticipated that a smaller site would be automated, and only one person would be required full time. For a larger acreage, potentially two people would work each shift. A small mobile trailer would be located on site for offices and sanitary facilities during construction and operation.

2.5.7.1.5 Construction Phase Activities

The site must be prepared prior to construction. Site preparation activities would include clearing of ground cover, development of access roads, and preparing the surface for drilling rigs and surface equipment. Clearing would vary depending on the chosen site; however, a maximum clearing of 291 acres would be required for roads and equipment locations. For 2,750 acres of land, a maximum of 23 miles of dirt and/or gravel access roads are anticipated. A crew of twenty equipped with appropriate machinery including front-end loaders and chippers would take about 20 days (3,200 man-hours) to prepare the site.

Additional construction activities including equipment footers or pads, field erection of equipment, drilling of wells, piping, utility tie-ins (electricity), etc. would require a larger crew and heavy machinery. A crew of about 20 – 50 construction personnel would require between 3 – 9 months to complete these tasks.

Erosion control measures will be implemented during construction to ensure sediment generated from construction will be controlled from impacting stormwater runoff. These measures include sufficient temporary and permanent erosion control devices and practices to control erosion and retain sediment within the boundaries of the site.

2.5.7.2 Case B – Co-Sequestration of Sour Gas (CO_2 and H_2S)

The technology to operate saline formation CO_2 and H_2S co-sequestration projects are currently in practice, although the projects relate to disposal by injection, rather than sequestration. CO_2 and H_2S co-sequestration projects in saline formations have occurred in various locations worldwide, specifically in the Alberta Basin in western Canada. By the end of 2003, 48 sites in western Canada, 20 sites in the U.S., and additional locations in the Middle East and North Africa were injecting acid gas into deep saline formations and depleted oil formations.

2.5.7.2.1 General Design and Operating Parameters

Favorable project conditions have been narrowed to a range of values to provide flexibility of project placement. These ranges have been derived from review of existing projects of injection into saline formations, as specified in the Case A description.

Typical model project parameters are summarized in Table2-25. To ensure the model project encompasses injection rates similar to a commercial project, the following range of daily injection rates would be used: 36 MT/day (13,140 MT/year) as a minimum from one well and 2,490 MT/day (909,100 MT/year) as a maximum from three wells. Based on the Gas Research Institute Topical Report (GRI, 1991), the maximum weight percent (wt%) of H_2S in the gas stream would be 25 percent. The minimum would be 2 wt%. Therefore, the anticipated maximum injection rates for CO_2 and H_2S are 681,800 MT/year and 227,300 MT/year, respectively.

Table 2-25. Case B - Co-Sequestration of CO_2/H_2S - Saline Formation Model Project Data Sheet.

Parameter	Minimum Value	Maximum Value	Basis of Data Assumption
Saline Formation Depth	3,000 feet	6,000 feet	Based on Frio, Nagaoka, and Sleipner Projects
Saline Formation Thickness	160 feet	1,000 feet	Based on Frio, Nagaoka, and Sleipner Projects
Transport Sour Gas to Site	Refer to Compression and Transport of Captured CO_2 Model Project Description		
Site Acreage	92	2,750	Based on the number of wells and the distance between
Distance between Wells	500 feet	2,000 feet	Minimum based on Frio and Nagaoka projects. Maximum based on extrapolation of Sleipner projections.
Injection Wells	1	20	Based on Frio, Nagaoka, and Sleipner Projects for minimum. Maximum based on twice the EOR injectivity. Wells are new..
Observation / Monitoring	1	8	Based on minimum of 1, but potentially 8 for larger acreage. All

Parameter	Minimum Value	Maximum Value	Basis of Data Assumption
Wells			wells are new.
Well Drilling Cuttings	4,200 cu.ft.	58,800 cu.ft.	Based on 8-inch diameter well with a maximum depth of 6,000 feet.
Clearing (acres)	9	291	Maximum based on 23 miles of 75'-right-of-ways for new roads, plus 3 acres per new well for equipment locations.
New Access Roads (miles)	0.3	23	New roads for new wells.
New CO_2 Distribution Piping to Injection (miles)	0.1	7.6	Maximum based on 3 distribution lines from central point between injection wells with minimum distances of 500 feet and 2000 feet respectively. All new piping, which will be placed in new road right-of-ways.
Total Average Sour Gas Injected (MT/day)	36	2,490	Based on Nagaoka and Sleipner Projects, respectively
Total Average Sour Gas Injected (MT/year)	13,140	909,100	Multiplied tpd by 365
CO_2 Injected (MT/year)	12,877	681,825	Based on minimum of 2 wt% H_2S/ 98 wt%CO_2 and maximum case of 25 wt% H_2S/ 75 wt% CO_2, respectively.
H_2S Injected (MT/year)	263	227,275	Based on a minimum of 2 wt% and maximum 25 wt%. Maximum wt % based on Gas Research Institute Topical Report (1991).
Personnel (Operations)	1 per shift	2 per shift	Minimum based on model project being an automated system
Distillate Fuel Usage	3,295 gal/yr	76,893 gal/yr	Calculated from required energy of heating unit and based on 8,760 hours per year.
Air Emissions from Heater using Distillate Fuel			
Methane (CH_4) (lb/hr)	0.00008	0.002	AP-42, Section 1.3, September 1998. Emission factor = 0.216 lb/1000 gal.
Nitrous Oxide (N_2O) (lb/hr)	0.00004	0.001	AP-42, Section 1.3, September 1998. Emission factor = 0.11 lb/1000 gal.
Carbon Dioxide (CO_2) (lb/hr)	8.4	195.7	AP-42, Section 1.3, September 1998. Emission factor = 22,300 lb/1000 gal.
Particulate Matter (PM) (lb/hr)	0.001	0.018	AP-42, Section 1.3, September 1998. Minimum emission factor (2 lb/1000 gal) is for Boilers <1 MMBtu/hr, maximum emission factor (2 lb/1000 gal) for Boilers >1 MMBtu/hr.
Nitrogen Oxides (NO_f) (lb/hr)	0.008	0.211	AP-42, Section 1.3, September 1998. Minimum emission factor (20 lb/1000 gal) is for Boilers <1 MMBtu/hr, maximum emission factor (24 lb/1000 gal) for Boilers >1 MMBtu/hr.
Carbon Monoxide (CO) (lb/hr)	0.002	0.044	AP-42, Section 1.3, September 1998. Minimum emission factor (5 lb/1000 gal) is for Boilers <1 MMBtu/hr, maximum emission factor (5 lb/1000 gal) for Boilers >1 MMBtu/hr.
Volatile Organic Compounds (VOC) (lb/hr)	0.0002	0.005	AP-42, Section 1.3, September 1998. Emission factor = 0.556 lb/1000 gal.

The number of injection wells would range from 1 to 20. The majority of other project data (site acreage, miles of access roads, etc.) is based off of the number of injection wells. Between 1 and 8 monitoring wells would be installed for various MM&V requirements. If multiple wells are drilled, they would typically be at various depths. These wells would monitor the stability of the sequestered CO_2 and H_2S injected in the saline formations. All injection and monitoring wells would be new construction.

Depending on the depth of the saline formation, wells may extend from 3,000 to 6,000 feet in depth, with the formation ranging from 160 feet to 1,000 feet thick. The ranges for the well depths and the saline formation thickness are based on all three existing field projects.

A range of 0.1 mile to 7.6 mile of 4-inch piping would be required to transport the CO_2 and H_2S to individual wells on site. This maximum of 0.3 mile is assuming the distribution lines would begin near a location central to the three injection wells and distribute out to each injection well. As discussed later, injection wells are a minimum of 500 feet from any observation well or injection well. This piping would be buried to ensure that seasonal temperatures do not affect line pressures, and thus injection rates. This dispersion system would connect to individual well sites via a 2-inch pipe.

The types of surface equipment for CO_2 and H_2S injection anticipated for the model project are discussed in the following paragraphs. The surface configuration for an injection well would consist of the following equipment (Hovorka et al., 2003; Kikuta et al., 2004). The Compression and Transport of Captured CO_2 Model Project Description compresses the gas stream to 3,000 psia. At least one main pump, and potentially a booster pump would regulate the injection pressure and flow rate. A heating unit would be anticipated as the CO_2 and H_2S would require temperature control. The heating unit would either use natural gas, diesel fuel, or electricity for operations. Inline monitors will ensure the CO_2 and H_2S is injected at the appropriate temperature. A SCADA system may be used to monitor and transmit flow rate, pressure, and temperature information to a central data collection point. The SCADA system would be solar powered with a battery backup. The footprint for the CO_2 and H_2S injection surface configuration is anticipated to be about 150 square feet.

Prior to injection, various methods of MM&V can be conducted to form a data baseline of the saline formation, groundwater formations, surface water, and gas monitoring. These technologies are then continued during injection, and for extensive time periods following injection. MM&V technologies may include seismic tomography and monitoring, wireline logging, measurement of in-situ temperature and pressure, and electromagnetic imaging (Kikuta et al., 2004; Techline, 2004).

2.5.7.2.2 Utility Requirements

Utility requirements for the model project include fuel usage and electricity. Fuel would be trucked on site for the injection well heating unit. No additional on-site fuel storage is anticipated. Fuel usage would range from approximately 3,295 gallons per year to 76,893 gallons per year for the minimum and maximum scenarios. Electricity would be required to operate the injection pumps and potentially the heating unit.

2.5.7.2.3 Environmental Process Discharge Streams

Air emissions associated with equipment operations, land use, aesthetics, and noise related to project activities would occur over a short duration of time or be intermittent in nature. Usage of distillate fuel is assumed for a conservative estimate of air emissions. Table 2-25 shows air emissions for the minimum and maximum scenarios. Refer to the CO_2 Compression and Transport Model Project description for additional information regarding environmental concerns.

Another potential concern is subsurface leakage of the formation fluids. Well leakage can be caused by inadequate annular seals or damaged casing in the production or injection wells. Leakage of saline water or gas from the subsurface formation can result from higher injection pressures, either by hydrofracturing or by fluids bypassing the caprock seal.

Well drilling cuttings would require collection and management. An estimated maximum 2,100 cubic feet of cuttings collection would occur at each well. This estimate is based on an 8-inch diameter well with a maximum depth of 6,000 feet. Consistent with local regulatory regulations, soils that are contaminated with petroleum hydrocarbons or other drilling-related chemicals will be encapsulated on site or disposed in a permitted waste management facility.

2.5.7.2.4 Site Requirements and Operations

It is assumed that the full-scale, commercial size model project would either be co-located with a CO_2 source, or would be located in an area relatively proximate (e.g. 10-20 miles) to a nearby major CO_2 source and/or existing CO_2 pipeline. Therefore, a nearby pipeline would provide the CO_2 for injection for the commercial-scale project. Truck (or rail) transport is assumed for the small-scale, field validation

R&D project. Refer to the Compression and Transport of Captured CO_2 Model Project Description for additional information. The site should range from 92 to 2,750 acres. A minimum distance between injection and observation wells would be 500 feet (NETL, 2003; Kikuta et al., 2004).

CO_2 and H_2S injection would occur continuously with three shifts. Monitoring is anticipated to operate prior to, during and following completion of CO_2 and H_2S injection. It is anticipated that a smaller site would be automated, and only one person would be required full time. For a larger acreage, potentially two people would work each shift. A small mobile trailer would be located on site for offices and sanitary facilities during construction and operation.

2.5.7.2.5 Construction Phase Activities

The site must be prepared prior to construction. Site preparation activities would include clearing of ground cover, development of access roads, and preparing the surface for drilling rigs and surface equipment. Clearing would vary depending on the chosen site; however, a maximum clearing of 291 acres would be required for roads and equipment locations. For 2,750 acres of land, a maximum of 23 miles of dirt and/or gravel access roads are anticipated. A crew of twenty equipped with appropriate machinery including front-end loaders and chippers would take about 20 days (3,200 man-hours) to prepare the site.

Additional construction activities including equipment footers or pads, field erection of equipment, drilling of wells, piping, utility tie-ins (electricity), etc. would require a larger crew and heavy machinery. A crew of approximately 20 to 50 construction personnel would require between 3 to 9 months to complete these tasks.

Erosion control measures will be implemented during construction to ensure sediment generated from construction will be controlled from impacting stormwater runoff. These measures include sufficient temporary and permanent erosion control devices and practices to control erosion and retain sediment within the boundaries of the site.

2.5.8 Basalt Formation Geologic Sequestration Model Project

This model project was developed to evaluate the impacts of geologic sequestration in basalt formations. The basalt formation geologic sequestration model project would consist of transporting the CO_2 gas stream on-site from a nearby source and injecting the gas stream into the basalt formation. The technology to install and operate basalt formation CO_2 sequestration projects is similar to that associated with EOR and saline formation geologic sequestration applications. However, with the exception of a very small, short term (i.e., several day) CO_2 injection field experiment (Matter, 2005), as of the 4th quarter 2005 there have been no CO_2 sequestration field projects in basalt formations conducted anywhere in the world. Thus, the design basis for this model project is largely conceptual and substantially based on the extensive characterization work by the U.S. DOE of the Columbia River Basalt Group (CRBG) and the U.S. Geological Survey in the U.S. Pacific Northwest (BSRCSP, 2005; USGS, 2005). Additional descriptions of current sequestration technologies are discussed in Section 2.2.

Basalt is a dark-colored igneous rock composed chiefly of aluminum silicate minerals and has fine-grained or glassy texture. The major elements in basalt are silica, aluminum, oxygen, calcium, iron and magnesium. Extensive basalt formations that may be attractive for carbon sequestration occur in the Pacific Northwest, the Southeastern U.S., and in several other U.S. regions. Because of the very limited study of basalts for carbon sequestration, basic information on injectivity, storage capacity, and rate of conversion of gaseous CO_2 to solid carbonates is not available. Insufficient data have been generated from these experiments to permit reliable projections of CO_2 conversion rates under large-scale sequestration conditions. Information is also lacking on the ability of basalts from other parts of the U.S. to support *in-situ* mineralization reactions (NETL, 2004).

The basalt model project description below includes the following elements:

- General design and operating parameters including MM&V;
- Utility requirements;
- Environmental concerns;
- Site requirements and operations; and
- Construction phase activities.

2.5.8.1 General Design and Operating Parameters

Based on the available information, favorable sites for CO_2 injection into basalt may have formation characteristics comparable to those of the model saline formation site. Typical project parameters for the basalt model project are summarized in Table 2-26. The model project for basalt would have the following range of CO_2 annual injection rates: 3,000 tons per year (2,722 MT per year) for a small pilot project, and 500,000 tons per year (453,592 MT per year) for a commercial-scale project. Using injection well spacing comparable to commercial scale, multi-well onshore saline applications, results in a maximum of 12 injection wells, at 2400 feet spacing between wells. The number of injection wells would range from 1 to 12, with the minimum wells and injection rate based on 2 pilot projects planned, one in the CRBG and one in India (McGrail, 2005 and Kumar, 2005). The majority of other project data (site acreage, miles of access roads, etc.) are derived from the number of injection wells.

Between 3 and 10 monitoring wells would be needed for various MM&V requirements. If multiple wells were drilled, they would typically be at various depths. These wells would monitor the stability of the sequestered CO_2 injected in the basalt formation. All injection and monitoring wells would be new construction. Depending on the depth of the basalt formation, which the CRBG formation depth ranging from 3,000 to 12,000 feet, wells may extend from 3,000 to 5,000 feet in depth, with the Grande Ronde formation of the CRBG ranging from 500 feet to 8,000 feet in thickness (Reidel, 2002).

A range of 0.1 mile to 5.5 miles of 4-inch piping would be required to distribute the CO_2 to individual wells on site. This maximum of 5.5 miles was based on the assumption that the distribution lines would begin near a location central to the four rows of three injection wells and distribute out to each injection well. This piping would be buried to ensure that seasonal temperatures do not affect line pressures, and thus injection rates. This dispersion system would connect to individual well sites via a 2-inch pipe. All piping would be new construction.

The types of surface equipment for CO_2 injection anticipated for the model project are discussed in the following paragraphs. The surface configuration for a CO_2 injection well would consist of the following equipment: at least one main pump, and potentially a booster pump would regulate the injection pressure and flow rate. Inline monitors will ensure the CO_2 is injected at the appropriate temperature. A Supervisory Control and Data Acquisition (SCADA) system may be used to monitor and transmit flow rate, pressure, and temperature information to a central data collection point. The SCADA system would be solar powered with a battery backup.

Prior to injection, various methods of MM&V can be conducted to form a data baseline of the basalt formation, deep groundwater, shallow aquifers, surface water, and gas monitoring. These activities are then continued during injection, and for extensive time periods following injection. MM&V technologies may include downhole vertical seismic tomography and profiling, wireline logging, downhole geochemical sampling, measurement of in-situ temperature and pressure, introduced tracers, and atmospheric monitoring.

2.5.8.2 Utility Requirements

Utility requirements for the model project include electricity. Electricity would be required to operate the injection pumps. These requirements are not expected to exceed those of EOR applications, so the EOR factor of 1.387 kW/MMscf was used here.

2.5.8.3 Environmental Process Discharge Streams

Air emissions associated with equipment operations, land use, aesthetics, and noise related to project activities would occur over a short duration of time or be intermittent in nature. Refer to the CO_2 Transport Model Project (see Section 2.5.4) description for additional information regarding environmental concerns.

Another potential concern is subsurface leakage of the formation fluids. Subsurface leakage of undesirable fluids from the injection well into shallower aquifers can result from inadequate annular well seals or damaged casing. Leakage of lower quality water or gas from the subsurface formation may also result from excessive injection pressures, either by hydrofracturing or by fluids escaping from the basalt formation along faults or fracture zones.

Well drilling cuttings would require collection and management. An estimated maximum 1,050 cubic feet of cuttings collection would occur at each 3,000-foot well. This estimate is based on an 8-inch diameter well. Consistent with local regulatory requirements, soils that are contaminated with hydrocarbons or other drilling-related chemicals will be encapsulated on site or disposed in a permitted waste management facility.

2.5.8.4 Site Requirements and Operations

It is assumed that the full-scale, commercial size model project would either be co-located with a CO_2 source, or would be located in an area relatively proximate (e.g. 10-20 miles) to a nearby major CO_2 source and/or existing CO_2 pipeline. Therefore, a nearby pipeline would provide the CO_2 for injection for the commercial-scale project. Truck (or rail) transport is assumed for the small-scale, field validation R&D project. Refer to the Compression and Transport of Captured CO_2 Model Project Description for additional information (Section 2.5.4). The site should range from approximately 60 to 2,600 acres. A minimum distance between injection and observation wells would be between 100 feet and 500 feet, respectively (NETL, 2003 and Kikuta, 2004); 400 foot spacing was selected. The maximum distance between commercial scale injection wells was estimated at 2,400 feet, approximately equal to that of the saline formation model project.

CO_2 injection would occur continuously with three shifts of operators. Monitoring is anticipated to operate prior to, during and following completion of CO_2 injection. It is anticipated that a smaller site would be automated, and only one person would be required full time. For a larger acreage, potentially two people would work each shift. A small mobile trailer would be located on site for offices and sanitary facilities during construction and operation.

2.5.8.5 Construction Phase Activities

Site preparation activities prior to construction would include clearing of ground cover, development of access roads, and preparing the surface for drilling rigs and surface equipment. Clearing would vary depending on the chosen site; however, a maximum clearing of 166 acres would be required for roads and equipment locations. For 2,600 acres of land, a maximum of 11 miles of dirt and/or gravel access roads are anticipated. A crew of 15 equipped with appropriate machinery including front-end loaders and chippers would take approximately 30 days (3600 man-hours) to prepare the site.

Additional construction activities including equipment footers or pads, field erection of equipment, drilling of wells, piping, and utility tie-ins (electricity) would require a larger crew and heavy machinery. A crew of approximately 20 to 50 construction personnel would require between 3 to 9 months to complete these tasks.

Erosion control measures would be implemented during construction to ensure sediment generated from construction will be controlled from impacting stormwater runoff. These measures include sufficient temporary and permanent erosion control devices and practices to control erosion and retain sediment within the boundaries of the site.

Table 2-26 Basalt Formation Model Project Data Sheet

Parameter	Minimum Value	Maximum Value	Basis of Data Assumption
Basalt Formation Depth	3,000 feet	12,000 feet	CRBG boreholes (8 total) stratigraphy data (Reidel, 2002).
Basalt Formation Thickness	500 feet	8,000 feet	Grande Ronde basalt formation of CRBG (Reidel, 2002).
Individual Basalt Flows Thickness	30 feet	300 feet	CRBG individual basalt flow thickness (Reidel, 2002).
Transport CO_2 to Site	Refer to Compression and Transport of Captured CO_2 Model Project Description		
Site Acreage	59	2,600	Based on the number of wells and the distance between.
Distance Between Wells	400 feet	2,400 feet	Minimum based on injection/monitoring well spacing of EOR and saline single injection well pilot projects. Maximum based on that of saline formation injection well-to-injection maximum well spacing (i.e., 2000 – 2,500 feet).
Injection Wells	1	12	All wells are new.
Well Depth	3,000 feet	5,000 feet	Minimum based on 800-1200m target injection zone for Phase II pilot planned in CRBG. Maximum = ½ that of deep saline formations, as basalt available at shallower depths, higher Mg/Ca concentrations for mineralization reactions, and avoid porosity reductions at greater depths.
Observation / Monitoring Wells	3	10	All wells are new. Minimum based on preliminary plan for CRBG pilot. Maximum based on interior cell and 4-corner grid external monitoring well placement.
Clearing (acres)	16	166	Minimum and maximum based on 0.5 mile and 11 miles, respectively, of 75’ right-of-ways for new roads, plus 3 acres per new well (injection and monitoring) for equipment locations.
New Access Roads (miles)	0.5	11	New roads for new wells.
New CO_2 Distribution Piping to Injection (miles)	0.1	5.5	Based on number of injection wells and distance between. Maximum based on 2 distribution lines from central point between injection wells with maximum spacing. New piping will be placed in new road right-of-ways.
Total Average CO_2 Injected	0.14 MMscfd	23.6 MMscfd for 12 wells	Ideal gas law mass-volume conversion.
Total Average CO_2 Injected	8.2 tpd	1,370 tpd	Average daily injection rate for total annual injection (based on 3,000 and 500,000 tons per year).
Total CO_2 Injected (MT/Year)	2,720	453,600	Minimum based on 2 pilots planned in U.S. Northwest and India (McGrail, 2005 and Kumar, 2005). Maximum project size = ½ that of other geologic sequestration technologies, due to lack of field project experience and development status.
Personnel (Operations)	1 per shift	2 per shift	Minimum based on model project being automated system.
Well Drilling Cuttings	4,200 cu.ft	38,400 cu.ft	Based on 8-inch diameter well with a maximum depth of 3,000 to 5,000 feet, respectively.
Utility Requirements	0.19 kW	32.7 kW	Based on 1.86 hp / MMscf = 1.387 kW / MMscf utility requirements of EOR projects.

2.5.9 Carbon Sequestration on Mined Lands Model Project (Reforestation)

In considering potential technologies and corresponding model projects for carbon sequestration, evaluating the impacts of two terrestrial sequestration approaches to sequestering CO_2 was selected as a model project. Long-lived forest stands act as natural carbon sinks for sequestering carbon in terrestrial systems over many years. The amount of CO_2 stored in a particular ecosystem can actually increase annually in correlation with biomass increases of the vegetation. The following processes described are generic in nature so as to be applicable to many regions of the country. The model project described below is based upon general standards for approximating how these projects can successfully sequester CO_2, as part of a reclamation program on mined lands.

One constraint to applying forestation/reforestation and no-till agriculture technologies in sequestering carbon is that the process is limited to areas where the climate and existing soils are suitable for this practice. For example, reforestation is not a feasible practice in the deserts of the Southwest U.S. where the annual rainfall is low and the vegetation (often low shrubs and cacti) is sparse and adapted to low moisture conditions. It is not that those areas cannot be revegetated or restored, but they will require a specific set of conditions and vegetation species, and are unlikely candidates for economical forestation/reforestation for sequestering CO_2. However, one of the attractions of this particular technology is that most regions of the U.S. are well suited for sequestration of CO_2 either by existing forest stands or re-vegetation.

The ability of a forest to sequester carbon is based on many factors. Descriptions of factors that could affect forest health and carbon sequestration are given in Section 4.2.3.8.

The following sections describe the basis for and characteristics of each of the two cases for the model project:

- General design and operating parameters of the model project;
- Environmental process discharge streams and benefits;
- Site requirements and operations;
- Installation/construction phase activities; and
- Monitoring, mitigation, and verification (MM&V).

2.5.9.1 Case A: Forestation on Mined Lands

Responsibility for terrestrial sequestration research is shared by many Federal agencies, and the DOE-NETL program coordinates activities in this area with the DOE Office of Science, U.S. Department of Agriculture, Environmental Protection Agency, and Department of Interior Office of Surface Mining, The scope of terrestrial sequestration options addressed in the DOE-NETL Carbon Sequestration Program is limited to the integration of energy production, conversion, and use with land reclamation. Specifically, this involves the reforestation and amendment of damaged soils. Field validation tests focus on improving the carbon storage of previously or abandoned mined land and optimizing land management practices. Current projects include demonstration of reforesting recently mined lands in Virginia, West Virginia, and Ohio and a smaller-scale demonstration integrating terrestrial sequestration with energy production, involving greater than 700 acres total of previously mined land. The focus is on enhancing the productivity of terrestrial ecosystems through the application of soil amendments, such as coal combustion byproducts, and biosolids from wastewater treatment facilities (NETL, 2004).

Much of the strip mining in the Eastern U.S. is on forested lands. Unfortunately, after mining most of these areas are restored as grasslands. However, much more carbon is stored in a hectare of forest than in a hectare of grasslands. Within the Appalachian coal region, there may be up to 400,000 hectares (1 million acres) of abandoned mined lands. These areas contain little or no vegetation, provide little wildlife habitat, and pollute streams. Reclamation and afforestation of these sites has the potential to sequester large quantities of carbon in terrestrial ecosystems. Approximately 1.6 million acres of land in the U.S. supports only limited vegetation due to past and present mining operations. Over 1.8 million hectares of land nationally (including 1.1 million hectares in the east) were under active coal mining permits during 2001; of these lands, over 600,000 hectares (including 200,000 hectares in the east) are currently classified as "disturbed". Converting these abandoned lands to productive forests has the potential of sequestering a long range total of over 100 million metric tons of carbon. DOE-NETL's terrestrial sequestration activities are aimed at developing hardwood and conifer forests on eastern U.S. coalfields, not only to sequester carbon but also to support a wood products economy, help control flooding, and provide clean water, wildlife habitat, biodiversity, and recreation (NETL, 2004).

Abandoned and previously reclaimed mine lands in the Appalachian region may provide excellent sites for enhanced terrestrial carbon sequestration through reforestation. Because soils in these areas are essentially devoid of carbon after mining, the planting of forests can dramatically affect carbon uptake of these sites, thus increasing carbon accumulation in soils and forest biomass. For example, DOE-NETL has initiated a reforestation project at several locations within Kentucky. These sites differ with respect to geology and reclamation practices. Various methods are being employed to decrease both physical and chemical limitations on plant growth so that the establishment of high value forest species (hardwood and conifers) is possible. The primary goal is to establish planting sites to demonstrate low compaction surface mine reclamation techniques for carbon sequestration through the growth and harvesting of high value trees (NETL, 2004).

When land is surface-mined, the entire forest, including shrub layer, tree canopy, root stocks, seed pools, animals, and microorganisms is removed. After reforestation reclamation, this complex forest can in time be restored to its original function and structure via forest succession. A combination of grasses, legumes, nurse shrubs and trees, and crop trees are established more or less simultaneously. Each plant type serves a specific reclamation function then yields to another plant type. Pioneer species such as legumes, shrubs, and resilient pine and hardwood species become established first, then eventually yield to the more site-sensitive hardwood crop trees as they close canopy. Reforestation best practices are designed to accelerate forest succession while providing land stabilization and erosion control (Burger, et. al., 2002).

2.5.9.1.1 <u>General Design and Operating Parameters</u>

Rates of carbon sequestration on forest lands depend on the management practices adopted, the species of trees involved, and the geographic area covered. For any given land-use change, sequestration rates will vary considerably depending on the region and vegetation species involved. For example, conversion to loblolly pine in the Southern Plains states leads to rapid uptake of CO_2, peaking at approximately 16 tons CO_2 per acre per year in the second decade of growth, and declining rapidly thereafter, with carbon uptake becoming insignificant after 70 years. In contrast, ponderosa pine plantations in the Mountain states region exhibit a gradually increasing rate of CO_2 sequestration over 70 years, peaking at about 11 tons CO_2 per acre per year, and declining gradually over the succeeding century. Forty to seventy-year uptake rates reported for these trees ranged from 6-7 tons CO_2/acre/year. Thus, the total quantity of carbon sequestered over the lifetime of a plantation may be greater in the case of ponderosa pine, but the sequestration occurs much later with loblolly pine, which is probably attributable to differing growth rates between species. Among various U.S. studies, the range of estimates for overall forest carbon sequestration potential is from 3 to 17 tons CO_2/acre-year (Stavins and Richards, 2005). Various U.S. based terrestrial reforestration sequestration projects have reported long-term uptake rates ranging from 5 – 20 tons CO_2/acre/year, with an average of 10 tons CO_2/acre-year.

Based on the above, for the forestation sequestration model project, long-range average CO_2 offset rates of 8-10 tons CO_2/acre-year are assumed (7.25 to 9.1 MT CO_2/acre-year). The DOE, UtiliTree and PowerTree U.S. projects range from 200 to 1,100 acres each (Kinsman, 2001; PowerTree, 2004). Various international projects involving tree planting or reforestation range from 1,000 acres to 500,000 acres, but with most projects significantly less than 100,000 acres (FAO/ISRIC, 2004). Therefore, the minimum and maximum project sizes for this analysis are based on 500 acres (DOE, UtiliTree/PowerTree project) and 10,000 acres (Southern Company/AEP/large international project) (Summer et al., 2004; Boyd, 2003; Loeffelman et al., 2005).

It is important to understand the magnitude of the hypothetical terrestrial sequestration programs under consideration. The amount of land involved is quite large—approximately 4 million acres for a program achieving 25 million tons of CO_2 sequestration per year and 15 million acres for a program achieving 100 million tons of CO_2 sequestration per year. This would be a large amount for the U.S. to absorb—and so a program of this size would need to be implemented gradually over many years. Additionally, these land requirements far exceed the total abandoned mine lands in the U.S. Therefore, to achieve these carbon sequestration goals, terrestrial sequestration will likely contribute only a small portion of the overall U.S. carbon sequestration program, and would have to be applied beyond mine lands alone.

Since about the 1980's, in several states mined land planted with trees has been designated as "unmanaged forest land", or "non-commercial forest land" in mining permits. Another forest land post-mining land use option is "commercial forest land' or "managed forest". Commercial forest land provides an opportunity to use alternative reclamation practices to achieve a wood production forestry management objective. For commercial forestry (and to maximize carbon sequestration potential), a minimum stocking of 400 trees per acre is required. Similarly, 600-700 trees per acre should be established for good forest stand development by a combination of planting, seeding, and natural invasion. Performance criteria for regulatory required bond release by mining companies have been achieved for forest land. Of particular importance are requirements relative to final surface grading, ground cover, and number of trees per acre. Grading should be minimized to avoid surface soil compaction, with small gullies left un-repaired. Ground cover must be adequate to control erosion and achieve the specified land use success standard (Burger et al., 2002).

A generalized description of the model project parameters is included in Table 2-28. The model includes the sequestration of CO_2 as a result of establishing a forest ecosystem in an area where it is non-existent at the present time. The general design of the project includes several steps:

- Develop objectives and goals for the project;
- Determine what type of project could feasibly meet the stated objectives or goals;
- Determine the size of the site required to fulfill the objectives and goals;
- Determine the type forest (ecosystem and species specific); and
- Determine the life of the project (typically this can range from 40 to 100 years).

2.5.9.1.2 Environmental Process Discharge Streams and Benefits

The model project is expected to contribute only insignificant increases in air or water pollutant emissions, primarily during the initial phases of site preparation and planting. Subsequent years could see the need for maintenance for weed/competition control and application of pesticides if needed. The increase of CO_2 and other emissions from maintenance and equipment use will be insignificant in comparison to the overall net CO_2 sequestration of the planted forest. Other environmental issues associated with any type of land disturbance include sedimentation and erosion issues, especially if located near a stream or ditch, decrease in air quality if working dry land due to dust or other sediments, and any type of oil/fuel leaks of machinery working on site preparation or maintenance. These issues can be avoided if best management practices are used when installing and maintaining the project. The project is only expected to produce negligible amounts of wastes.

The benefits of forestation will improve degraded sites by addressing water quality issues of erosion and sedimentation as the forest becomes established. Forestation projects will also provide additional benefits such as increased biodiversity, restoration of wildlife habitats, enhanced flood control, provide public recreation opportunities, and help support a wood products economy. Therefore, given the insignificance of any environmental concerns, and the broad and diverse suite of associated environmental benefits, forestation sequestration projects will have only positive overall impacts on the environment.

Reclaimed mine soil sites covering a wide range of quality have been constructed, from sites on which trees are unable to survive, to sites on which trees are growing at rates faster than on natural, undisturbed soils; when reclaimed properly, mine soils can produce a harvestable tree stand in 35 years with six times more board-foot volume than that produced on a poor quality site (Torbert et al., 1988). Hardwoods growing on poor sites have virtually no commercial value, while timber value of hardwoods on good sites can be as much or more than that on non-mine sites with product values many times greater than that from a poor site (Burger et al., 2002).

2.5.9.1.3 Site Requirements and Operations

The land design of a forestation/reforestation project can range in size from small tracts of isolated land to very large continuous tracts depending on what is available and what other specific objectives the project may have such as restoring a bottomland hardwood forest, maintaining a sustainable timber reserve, or reclaiming a mining site. The amount of CO_2 sequestered will be directly proportional to the size of the project site, number of trees present, and the species of these trees. Logically, the larger the site the more CO_2 can be sequestered due to the number of trees and potential amount of biomass that each site can support. However, factors such as spacing requirements can affect this ratio. For example a smaller site may be designed with a 10-foot by 10-foot tree spacing while a larger site may be at a 15-foot by 15-foot spacing and therefore, each will support approximately the same number of trees and associated biomass.

Table 2-27 gives estimates of tract size and number of trees on those sites depending on spacing densities and therefore, approximates the amount of biomass per site available to capture CO_2.

Table 2-27. Number of Trees by Tract Size

Land Area of Size (acres)	Spacing of Species - 10’ by 10’ Spacing	Spacing of Species - 15’ by 15’ Spacing
	Number of Trees on Site	
10	4,350	1,940
50	21,750	9,700
100	43,500	19,400
500	217,500	97,000
1,000	435,000	194,000
5,000	2,175,000	970,000
10,000	4,350,000	1,940,000
50,000	21,750,000	9,700,000

Determining the type of forest ecosystem desired from a reforestation project must be defined early in the process as this will affect the site selection, species to plant, and site preparation. If the desired community is a plantation, then the site requirements such as soil type and rainfall are known and an appropriate site can be acquired for a single species composition. However, if a more diverse, naturalized forest ecosystem is the goal, then the species selected should approximate a natural community with appropriate species, different community layers, staggered spacing, etc. Again, all of these issues need to be determined when initially designing the site and subsequently developing the planting scheme.

The following conditions are necessary for proper tree growth and survivability on mined lands:

- The final surface layer must be composed of an acceptable rooting medium, placed on the surface to a depth of at least four feet to accommodate deeply rooted trees, and which is less intensively graded to minimize soil compaction.
- During the reclamation process, all highly alkaline or acidic materials with excessive soluble salt levels should be covered with four to six feet of acceptable rooting medium that will support trees.
- Select tree species that provide long-term erosion control, are compatible with one another, and are suited to site-specific conditions.
- Ground cover should include grasses and legume species that are slow growing, pH tolerant, and can be established in a bare mineral spoil; aggressive or invasive species must be avoided. Tree species selection should be based on an approved post-mining land use and site specific characteristics, whether it be a non-commercial (unmanaged) forest land, commercial (managed) forest land, or an area managed for fish and wildlife use (Campbell, 1997).

Two categories of trees are recommended: crop trees, or commercially valuable timber crop species, and nitrogen-fixing wildlife/nurse trees (or shrubs). Crop trees are long-lived species that offer value to landowners as salable forest products. Commonly planted crop trees include pines, poplar, ash, maple, and other hardwood species. On well-constructed mine soils, most native hardwood species grow well, with critical growth and survival factors including spoil type, compaction, slope aspect and position, and competition from ground cover grasses and legumes. Nurse trees are planted to assist the crop trees by enhancing the organic matter and nitrogen status of the soil, and improving soil physical properties. Nurse trees will die or can be cut out after 15 to 20 years when crop trees need additional growing space (Burger et al., 2002).

When selecting a site for a reforestation project, it is very important to realize the costs associated with site acquisition, as the most important factor affecting the cost of forestry-based carbon sequestration in the U.S. is the opportunity cost of land (i.e., the value of the affected land for alternative uses). Relevant opportunity costs include costs for land, conversion, plantation, establishment, and maintenance, as well as competing costs and prices for other land uses (e.g., agricultural).

Average farmland costs across the nation vary significantly, averaging $1360/acre. The low end averages $265/acre in New Mexico spiraling upward to $10,200/acre in Connecticut and Rhode Island (USDA 2004a). One option is leasing land which will defray the costs associated with purchasing land. However, other options to include purchasing the land outright will require some form of legal agreement/easement to assure the protection of the site for the life of project. This is a cost associated with developing the forestation/reforestation project. The greatest cost savings associated with reforestation as compared to creating hayland/pasture is due to reduced need for grading. Planting 600 trees/acre can be accomplished for about $300/acre provided soil compaction has been avoided and a tree-compatible ground cover has been established. Under these conditions, enough trees will surviv to result in a viable forest (Burger et al., 2002). The costs of land, planting of groundcover and trees, and forest management for timber production and/or creation of wildlife habitat will affect the overall potential for implementing forest-based CO_2 sequestration projects in the U.S.

Based on previous reforestation terrestrial sequestration projects, the model project is expected to require 500 acres of land for the pilot scale project, and 10,000 acres of land for the commercial scale project. With an active mining or bond released site, it is assumed that no new access roads will be required; however, for abandoned mine sites, it is estimated that a maximum of 4 to 50 miles of access roads would need to be re-established to support the pilot and commercial scale reforestation projects, respectively.

2.5.9.1.4 Construction Phase Activities

After acquiring the site, the first step is to prepare the site for planting. Preparations can include several tasks which are entirely dependent on existing site conditions. The site may need to be cleared, disked, subsoiled, soil amendments and/or pre-planting herbicides applied, etc. Again, these tasks all depend on the needs and condition of the individual site. Site preparations are estimated to require three crews of four with the appropriate machinery 30 days to prepare the 500 acre pilot scale site, and six crews of four 300 days to prepare the 10,000 acre commercial scale site.

Site preparation may require herbicide treatment, depending on the existing species of ground cover. There are several methods to prepare a mined site by ripping. One method is to deep cross-rip with a single tine using the planting spacing as the guideline. The soil should be ripped a minimum of three feet, more if possible, because the deeper the roots can penetrate the higher the resultant site index (i.e., height of the tallest trees at a given age). Rocks are pulled out from below for maximum fracture. Other methods use multiple tine rippers with no cross ripping, excavators, and smaller ripper configurations.

The next step towards completing the project is planting or seeding the prepared site. Number of seedlings can also vary depending on spacing including the desired visual effect and species as mentioned earlier. A 10-foot by 10-foot spacing would require 435 plants/acre and a 15-foot by 15-foot spacing would require 194 plants/acre. There are several methodologies for planting the seedlings; two of the most common are mechanical or hand planting, both of which should be completed from November to April, prior to the beginning of the respective growing season in the area. Seedlings should be planted as soon as possible in late winter or early spring after the ground has thawed, as the soil is usually wetter, more conducive to root growth, and roots are established before the weather turns warm enough for shoot growth to begin (Burger, 2002). Additional planting may be necessary in later seasons if there is a large percentage of mortality in the plants. It is estimated that a crew of three would take 2 months to plant the 500 acre pilot scale site, and a crew of twelve would take 10 months to plant the 10,000 commercial scale site.

The last steps in reforestation will include several tasks after planting. Following establishment of a forestation project, there are ongoing maintenance activities and costs, including those associated with fertilization, thinning, security, and other MM&V activities necessary to realize expected carbon sequestration results. Activities and costs associated with fire and pest protection, as well as preventing the establishment of noxious and/or invasive plant species, may also be incurred. These tasks may or may not be necessary dependent on weather, site conditions and any other requirements of the project, including post-planting herbicides, pesticides, additional soil amendments, post planting monitoring, and possibly cultivation, depending on plant competition, etc. A final step that may occur 5-10+ years on the horizon includes thinning and/or harvesting if the site requirements are such.

2.5.9.1.5 Utility Requirements

No utility requirements are necessary in this forestation/reforestation model project case.

2.5.9.1.6 Monitoring, Mitigation, and Verification (MM&V)

Monitoring, mitigation, and verification of carbon cycling in forests, wetlands and riparian zones, and agricultural practices provide significant challenges, and most methods are not simple or rapid assessments (Wylynko, 1999). A variety of techniques are available to monitor and verify carbon storage in forests and other terrestrial systems, including field site measurements like biomass surveys (considering research studies, surveys, and inventories), and measurements of soil carbon, or modeling and remote sensing techniques (Ferguson et al., 2003).

Many groups believe that accounting for changes in terrestrial carbon stocks is inherently more difficult than for combustion or other industrial processes. Two significant problems are resolution, the ability to recognize small changes in large numbers, and maintaining the infrastructure needed for regular measurement of change in carbon stocks. Temporal and spatial variability contribute to higher uncertainty in estimates of carbon stocks. Accounting for reforestation project-level activities is different from national-level accounting, because project-level MM&V does not need to be as spatially comprehensive. However, lack of spatially comprehensive accounting of carbon stocks for individual projects may make it more difficult to recognize and compensate for project CO_2 losses (Schlamadinger and Marland, 2000).

Given that, DOE-NETL has Carbon Sequestration Program MM&V goals to develop instrumentation and measurement protocols to accurately monitor, mitigate, and verify carbon storage, and provide for 95 percent of CO_2 uptake in a terrestrial ecosystem to be credited. Above-ground MM&V is specific to terrestrial sequestration and involves quantification of the above-ground carbon stored in the forest vegetation. Traditional field practices provide fairly accurate estimates of above-ground carbon, but those methods are time consuming and labor intensive. In response to that, DOE-NETL is developing aerial and satellite-based technology to study forestation projects, to determine their carbon sequestration potential, and validate software models to predict carbon storage in forests. DOE-NETL is funding the development of Multi-spectral, 3-Dimensional Aerial Digital Imagery (M3DADI) for terrestrial sequestration MM&V. Dual cameras and laser are attached to an airplane to create a three-dimensional image of a forest plot. From correlations with stock inventories and ground measurements, these modeled images are used to estimate the amount of carbon sequestered. The technology is being validated in several large forestation projects by comparing this technology to conventional sampling methods (NETL, 2004).

For this model project case, it is anticipated that conventional field sampling and analytical procedures would be utilized as part of a pilot scale forestation project. Conversely, a much larger commercial scale project would likely utilize DOE-NETL's M3DADI technology.

2.5.9.2 Case B: No-Till Agriculture on Mined Lands

The area of research on carbon sequestration associated with agricultural practices is led by the USDA, and supported by other government agencies and non-governmental organizations (NGOs). However, as part of the Phase II pilot field validation tests, one or more agricultural practice-based projects have been selected and subsequently executed in the field. Additionally, DOE-NETL does have several ongoing research projects investigating methodologies and developing instrumentation for monitoring soil carbon contents. Therefore, this summary case on no-till agriculture is included in the carbon sequestration by mined lands model project, to serve in part as a relative descriptor by which any future DOE-NETL agricultural practice field test projects could be assessed.

Cropland agriculture results in GHG emissions from multiple sources, with the magnitude of emissions determined, in part, by land management practices. Cultivation and management of soils leads to emissions of N_2O, CH_4, and CO_2. However, agricultural soils can also mitigate GHG emissions through the biological uptake of organic carbon in soils via CO_2 removal from the atmosphere (USDA, 2004b).

The size of CO_2 emissions and sinks in soils is related to the amount of organic carbon stored in soils. Changes in soil organic carbon content are related to carbon inputs, e.g., atmospheric CO_2 fixed as carbon in plant tissue through photosynthesis, and soil carbon losses mainly caused by decomposition of soil organic matter causing CO_2 emissions. Land use and management affect the net balance of CO_2 uptake and loss in soils through modifying carbon inputs and rates of decomposition of organic matter. Changes in agricultural practices such as tillage can modify both organic matter inputs and decomposition, thus resulting in a net flux of CO_2 to or from soils (Houghton et al., 1997).

After mining operations, or decades of previous cultivation, most soils have likely stabilized their soil carbon content at lower carbon levels. Changes in land use or management practices that result in increased organic inputs or decreased oxidation of organic matter, e.g., reduction or elimination of tillage, will result in a net accumulation of soil organic carbon until a new equilibrium is achieved (USDA, 2004b).

On an area basis, the amount of carbon stored in agricultural soils typically exceeds that stored in vegetation in most ecosystems, including forests. However, in the U.S. the net annual forest carbon stock change resulting in increased carbon sequestration far exceeds the total GHG emissions associated with cropland agriculture (by a factor of 4 to 5). Additionally, the total U.S. carbon sequestered via cropland management and the Conservation Reserve Program is on the order of only 20 MMTCO$_2$/year (USDA, 2004b). Given the above, and that forestation CO_2 sequestration rates on the order of 10 tons CO_2/acre-year are much higher than that for no-till agricultural practices, this no-till agriculture case will have much less of a carbon sequestration contribution than a forestation project of equal size. Therefore, the forestation case serves as the basis of the carbon sequestration by mined lands model project.

In the MM&V area, soil MM&V involves tracking carbon uptake and storage in the first several feet of topsoil. DOE-NETL is developing two instrumentation approaches to monitoring soil carbon: Laser Induced Breakdown Spectroscopy (LIBS), and Inelastic Neutron Scattering (INS) soil carbon analyzer. The LIBS system offers the ability to distinguish between organic and inorganic carbon, and rapid field-deployable, portable, cost effective method for soil carbon determination. The INS system offers a non-invasive, non-destructive means of continuously monitoring the soil carbon inventory over both specific plots, and large areas. Either one or both of these MM&V technologies could support soil carbon monitoring in a no-till agriculture field test.

Table 2-28. Forestation/ Reforestation on Mined Lands Model Project Data Sheet

Parameter	Activity Description/ Basis	Low	High
Site Acquisition (acres)	Based on small DOE or UtiliTree demonstration project at low end, and large commercial utility or international project at high end.	500	10,000
Number of Trees (approx.)	Based on tight 10' by 10' spacing to maximize sequestration rates.	200,000	4,400,000
CO_2 Sequestration Rate (tons CO_2/acre-yr)	Based on several DOE/UtilTree demonstration project estimates, and mid-range of publicly reported estimates in the U.S.	8	10
CO_2 Sequestration, (tons/yr)		4,000	100,000
CO_2 Sequestration, (MT/yr)		3,630	90,720
CO_2 Sequestration Total (million tons)	Assume 70-year life, median of 40-100 year basis of publicly reported estimates	0.28	7.0
Site /Land Preparation: Clearing, Disking, Ripping, Pre-planting Weed Control, Fertilization (Months)	Required to prepare soil; sometimes necessary in site preparation due to severe compaction – equipment needed include tractor and subsoiler plow, herbicide and tractor, sprayer, fertilizer and tractor, fertilizer spreader equipment, labor.	1	10
Hand Planting (Months)	Timing Nov. to April.	2	N.A.
Mechanical Planting (Months)	Timing Nov. to April.	N.A.	10

2.5.10 Co-Sequestration Model Project

This model project was developed to evaluate the environmental-related considerations associated with the upstream processing steps for co-sequestration of CO_2 and H_2S. Such a co-sequestration approach would involve either EOR operations, or other geologic CO_2 sequestration (and H_2S disposal) in saline formations; therefore, a CO_2/H_2S co-sequestration case is included in each of those two model projects. This model project focuses on the two upstream gas processing/capture options for providing the co-sequestration gas stream. In the first option, CO_2 and H_2S are recovered as a byproduct from integrated gasification with combined cycle power generation technology (IGCC). In the second option, CO_2 and H_2S are recovered from sour associated gas production operations in the oil and gas industry.

The key aspects of the model project related to environmental considerations are described in the following sections:

- General design and operating parameters of the project, with primary focus on the gas-water shift and acid gas removal and recovery operations for the IGCC case, and the acid gas removal and sulfur recovery for the sour gas case;
- Utility requirements;
- Environmental process discharge streams;
- Site requirements and operations; and
- Construction phase activities.

2.5.10.1 Case A: IGCC with CO_2/H_2S Capture

The IGCC generation process integrates a gasification system with a conventional combustion turbine combined cycle power generation unit. The gasification process converts coal, or other solid or liquid feedstocks, into a hydrogen-rich gaseous fuel stream (referred to as synthesis gas or syngas). The syngas is then used to power a conventional combustion turbine combined cycle power plant with significantly lower SO_x, PM, mercury, and NO_x emissions. For the purposes of this model project case, the carbon in the raw syngas stream (in the form of CO) is converted to CO_2, separated, and recovered, together with H_2S.

Both the gasification process and the combined cycle generation technology are widely accepted as mature technologies. However, the integration of IGCC technologies is relatively new, with capital costs about 20-25 percent higher than conventional pulverized coal (PC) power systems. The integration of gasification with combined cycle technology is currently in commercial operation in few power plants[1], with Polk River, Florida and Wabash, Indiana in operation in the U.S.

In addition, the downstream gasification process steps to generate, separate, and recover CO_2 are commercially demonstrated. The Great Plains Synfuels Plant process recovers acid gas (CO_2 and H_2S) for resale and pipeline transport to the Weyburn field in Alberta, Canada for EOR operations. Therefore, all process operations associated with the model plant are based on commercially demonstrated technology. Advanced technologies are being developed for several of the process operations to enhance the system overall efficiencies, which are identified in the following process description section.

[1] There are 12 major IGCC plants in operation internationally, with 5 of those designed with the primary intent of commercial-scale electricity production. The remaining applications are in refining and petrochemical service, with electricity production as a secondary process.

2.5.10.1.1 General Design and Operating Parameters

Model Plant Process Description. The process flow for the IGCC with CO_2 recovery model project is illustrated in Figure 2-13. The primary unit operations in the plant include:

- Coal handling and feed slurry preparation;
- Air separation and coal gasification process;
- Water-gas shift and syngas humidification;
- CO_2 and H_2S separation and compression; and
- Combined cycle power generation.

As shown in Figure 2-13, coal feedstock is crushed, pulverized, and mixed with water to form a slurry for injection. The coal slurry is heated and fed to the gasification injection system. Oxygen of 95% purity is separated from air in a cryogenic air separation unit, which includes multi-stage compression, thermal swing absorption, and cryogenic distillation to separate the purified oxygen feed.[2]

The gasification technology assumed for this model project case is an entrained-flow reactor design.[3] Gasification occurs in an oxygen-limited reducing environment, where partial oxidation creates heat and a series of chemical reactions produce syngas. In the primary gasification zone, the heated coal slurry, oxygen, and recycled char from the candle filter are injected. The primary gasification zone operates above the ash fusion temperature (over 1200 deg. C), to allow the molten slag to flow from the reactor for removal, quenching and disposal (or resale for construction building products, etc.). The gaseous stream formed from the exothermic, partial oxidation process in the primary zone passes to the secondary zone. Coal slurry and raw fuel gas recycle are injected in the secondary zone, where the gasification reactions are endothermic, with exit gas temperatures of around 1040 deg. C. Waste heat is recovered from the raw gas stream to generate high-pressure process steam. Char and fly ash produced in the gasifier is entrained in the raw gas stream and removed in a particulate candle filter downstream of the waste heat recovery.

The cooled raw gas is mixed with steam and passed through high- and low-temperature water-gas shift reactors used to oxidize the CO in the raw fuel gas to CO_2. The fuel gas is cooled and routed to an acid gas removal (AGR) unit using Selexol[4] as the solvent. The AGR unit is a counter-current gas absorber unit that contacts the fuel gas stream with Selexol to remove CO_2 and H_2S from the fuel gas. The sweetened fuel gas stream exiting the top of the AGR separator is saturated with water (i.e., humidified), and then combusted in the gas turbine for combined cycle power generation. The fuel gas humidification process is designed to lower burner temperatures during combustion of the fuel gas in the combustion turbine, resulting in reduced NO_X emissions from power generation.

The rich Selexol from the AGR unit is regenerated by stripping the CO_2 and H_2S from the rich Selexol solvent in a regeneration process. The lean Selexol from the bottom of the regenerator is recycled back to the AGR separation unit, while the regenerator overhead stream, concentrated CO_2 and H_2S, is condensed to remove water, then compressed in multi-stage, intercooled compressors with glycol (or molecular sieve) dehydration to supercritical conditions. This concentrated H_2S-laden CO_2 stream is metered and transported via pipeline for EOR operations.

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[2] Advanced air separation technologies are under development, including membrane separation with significantly reduced energy intensity. For the model project, conventional cryogenic air separation technology is assumed based on commercial availability and demonstration.
[3] Commercially available gasification technologies include moving-bed reactors, fluidized-bed reactors, and entrained-flow reactors. Nearly all commercial IGCC systems in operation or under construction are based on entrained-flow gasifiers (commercial technology vendors include ChevronTexaco, ConocoPhillips, Shell, Prenflo, and Noell).
[4] Selexol is a physical absorption process favored at high pressure operation.

Model Project Design and Operating Parameters. Two model project sizes were considered for evaluation of the environmental considerations, based on combined cycle generation capacity as the critical design factor. The lower model plant capacity limit is consistent with the EOR model project size limitations as a pilot scale operation. For this scenario, the IGCC operation would be assumed to be an existing operation, such as the Wabash Power Station in Indiana, with a slipstream of the amine regenerator overhead supplying the CO_2 stream for an EOR (or saline formation) pilot project. For this low capacity scenario, the overall impacts on the IGCC facility operations and emissions would be minimal. In addition, this case example would have similar or lower impacts than the low capacity scenario for the post-combustion capture model; therefore, detailed calculations for the low capacity scenario are not included here. Also, IGCC slipstream-based CO_2/H_2S co-sequestration pilot projects are not anticipated to be a part of the Phase II field validation tests.

The high capacity model plant is based on two Siemens V94.2 gas turbine units in combined cycle configuration for a net output of 520 MW. This plant size is representative of the largest commercial installations of IGCC technology, although the existing plants use refinery residue instead of coal as feedstock. The gasification technology assumed is ChevronTexaco oxygen blown, entrained flow design. Such a large scale project could be performed at an existing gasification site, or be based on a new, greenfield plant.

Table 2-31 includes the model project design and operating parameters for the high capacity plant. Plant efficiencies of 37 percent are lower than IGCC technology without CO_2 capture and compression facilities (see following section for CO_2 recovery auxiliary power requirements). The model plant performance profiles are scaled based on design specifications from the EPRI study (EPRI, 2000), or other sources as noted, where data for actual applications are not available.

2.5.10.1.2 Utility Requirements

Utility requirements included in Table 2-31 are for the CO_2/H_2S capture and recovery steps of the IGCC plant. The plant-wide auxiliary power requirements for IGCC with CO_2 recovery are summarized as a percentage of the total auxiliary load in Table 2-29. As shown, the cryogenic air separation unit accounts for a large fraction (around 29 percent) of the parasitic load of an IGCC facility. The incremental electricity requirements for the CO_2 capture process steps are minimal, as the compression operations are already captured under the CO_2 transport model plant. These differences are captured in Table 2-31, based on published data for IGCC with and without CO_2 capture.

Table 2-29. Auxiliary Power Requirements for IGCC.

Process Unit Operation	Auxiliary Load (% total auxiliary load)
Air separation plant	29
CO_2 separation in AGR Selexol plant	7
CO_2 compression	20
Oxygen boost compressor	12
High pressure boiler feed pump	3
Balance of plant	29
Total auxiliary power requirements as % of gross generation	18 (% of gross power)

Source: EPRI, 2000.

Water make-up rates shown in Table 2-31 are for the entire IGCC plant, as well as for the utility requirements for the CO_2 separation operations. For the CO_2 operations, cooling water is used primarily to wash the syngas stream exiting the absorber, with make-up water to account for system losses. Make-up water requirements for the CO_2 operations range are 535 gpm for the high capacity model plant.

Solvent recirculation rates for the AGR unit were assumed as a basis to quantify the total solvent make-up rates. Data from published studies were used as the basis for the estimates. Total solvent make-up rates are estimated at 7-14 gpm, or over 20,000 gallons per day for the high capacity model plant. Solvent would be delivered to site via railcar or tank truck.

During the absorption and regeneration processes, entrained solids and chemicals accumulate in the amine solution impairing the treatment efficiency and contributing to foaming and tray clogging. Chemical additives are injected in the recirculated amine solution, including corrosion inhibitors and foam breakers. Soda ash (Na_2CO_3) is used to aid in the precipitation of salts in the amine regenerator. A slipstream of the amine solution is filtered through mechanical filters and activated carbon filters to maintain the amine solution quality.

Hydrated lime is used in the wastewater neutralization process to neutralize the acidic wastewater.

Miscellaneous systems consisting of fuel oil, service air, instrument air, and service water will be needed. The fuel oil used for IGCC start-up and a small auxiliary boiler will be stored in a 200,000 gallon storage tank.

2.5.10.1.3 Environmental Process Discharge Streams

Air Pollutant Emissions. The proposed model project would not result in increases in pollutant air emissions. The IGCC model project will result in decreased overall air pollutant emissions as compared to traditional pulverized coal power generation. IGCC power plants achieve air emissions control during the syngas clean-up process, prior to combustion in the combined cycle plant. Compared to post-combustion emissions control, IGCC offers more cost effective control in treating concentrated, higher pressure and lower mass flow streams as compared to conventional flue gas treatment technologies.

Table 2-30 provides the projected air emissions levels from IGCC with CO_2 recovery technology, compared to NSPS levels for coal power generation. These emissions represent plant-wide emissions, not just the process steps associated with CO_2 recovery. Incremental air pollutant emissions from the CO_2 separation and capture process are negligible, with the exception of CO_2 emissions. CO_2 emissions from the IGCC with CO_2 recovery model plant would be substantively lower than a conventional IGCC without CO_2 capture. Further, emissions of SO_x would actually represent a net decrease in overall sulfur emissions from the avoidance of downstream sulfur removal operations, although overall emissions of SO_x are very low.

Table 2-30. Plant-wide Environmental Performance of IGCC with CO_2 Capture Technology

Air Pollutant	Projected Emissions Levels for IGCC		Coal Power Plant NSPS Limits Lb/MMBtu (HHV)
	Lb/MWh	Lb/MMBtu (HHV)	
SO_X	0.11a – 0.7 b	0.013 a – 0.08 b	1.20
NO_X	0.25 a – 0.77 b	0.028 a – 0.08 b	0.15
CO	0.32 c	0.036 c	
PM	0.100 b	0.011 b	0.030
VOC	0.01 c	0.001 c	
CO_2	162d	21.4 d	

[a] Based on NETL/EPRI, Updated Cost and Performance Estimates for Fossil Fuel Power Plants with CO_2 Removal, Dec. 2002.

[b] Based on NETL, Major Environmental Aspects of Gasification-Based Power Generation Technologies, Dec. 2002.

[c] Based on ChevronTexaco, May 6, 2003.

[d] Based on EPRI, Dec. 2000.

For the entire IGCC plant, SO_x emissions are dictated by: a) the sulfur content of the coal feedstock, and b) the H_2S removal efficiency in the acid gas removal process for syngas clean-up and CO_2 recovery. High temperature gasification of coal produces H_2S and small amounts of carbonyl sulfide (COS). The acid gas removal process removes 95 to 99+ percent of the sulfur in the raw syngas. The remaining sulfur in the syngas stream is oxidized to SO_2 in the combustion turbine.

Likewise, CO and CO_2 emissions are minimized by the post-gasifier water-gas shift reaction oxidizing CO to CO_2, and the subsequent acid gas removal process to remove CO_2 from the syngas stream. Levels of CO_2 emissions from the power plant will be based on:

a) the water-gas shift reaction conversion efficiency, and

b) the CO_2 removal efficiency in the acid gas removal unit.

NO_X emissions are inherently low due to very low levels of fuel bound nitrogen in syngas, as well as the lowered turbine flame temperatures achievable with combustion of humidified syngas, coupled with steam injection, to limit thermal NO_f formation. Particulate matter is reduced through the separation of the char and ash entrained in the gasification process and recovery of molten slag from the gasification reactor.

Water and Solid Waste. IGCC facilities use water for the plant's steam cycle as boiler feedwater, cooling water and for other processes, such as syngas humidification and acid gas removal aqueous solvent make-up. Most process water in an IGCC plant is recycled to the plant, which minimizes consumption and discharge.

The acidic wastewater is neutralized with hydrated lime, oxidized by air injection, and flocculated to remove solids. The sludge would be dewatered and disposed of off-site.

The largest quantity of solid waste from an IGCC facility is slag, which is a non-leachable material that can be sold as a byproduct for applications such as asphalt paving aggregate or construction backfill.

2.5.10.1.4 Site Requirements and Operations

Coal is delivered to the site by unit trains of 100-ton railcars. Each unit train consists of 50-100 railcars, which are unloaded into 2-3 receiving hoppers. The coal is then conveyed to a reclaim pile. Coal from the reclaim pile is fed to a surge bin located in the crusher tower. Crushed coal is conveyed to 2-4 storage silos. The coal from the storage silo is fed to a rod-mill to pulverize the coal and mixed with water to form a slurry, heated, and stored in an agitated slurry tank.

Gasifier technology is assumed to be entrained-flow, oxygen blown technology with a maximum coal throughput per gasifier of 1,250 tpd (dry, with heating value of coal of 11,700 Btu/lb, HHV). The high capacity model plant (520 MW, net) would require up to 6 gasification trains.

The raw syngas is treated in 2-4 water-gas shift trains of high and low temperature shift reactors, steam generators, and fuel gas expanders.

The CO_2 recovery plant would include 2-4 absorber and regeneraton trains. Each absorber train would include 3 absorber towers, for a total of 6-12 absorber towers with approximate dimensions of 15 ft. diameter and 80 ft. height. Likewise, each regeneration train would include 2-4 stripper towers, with approximate dimensions of 15 ft. diameter by 75 ft.

The CO_2 and H_2S stream recovered from the amine regeneration strippers is compressed in 1-2 multiple-stage, intercooled compressors to supercritical conditions. During compression, the CO_2 stream is dehydrated in a triethylene glycol (TEG) unit. The temperature and water content of the CO_2/H_2S stream are important design parameters to avoid hydrate formation and corrosion. Methanol may be injected to avoid hydrate formation.

Fuel oil, amine solvent, soda ash, and hydrated lime are delivered by truck. Truck roadways and unloading stations must be provided. Storage hoppers for soda ash and hydrated lime are required, as well as storage tanks for fuel oil and amine solvent. For the amine solvent, from 10,000 to over 20,000 gallons per day will be required. Assuming delivery in 17,000 gallon tank trucks, daily deliveries would be required or weekly in railcars.

Liquid and solid wastes that require disposal from the site include reclaimer sludge, spent carbon from the amine filter beds, and slag disposal or resale. Spent carbon is trucked each week to a landfill for disposal. Slag is trucked to a near-by construction site or industrial user.

Based on the equipment required for the acid gas recovery operations of the IGCC plant, the model project is expected to require about 30 acres of land for the commercial scale project. The IGCC plant access roads are assumed to be adequate for the acid gas recovery operations. To maintain operations of the commercial scale facility, about 12 full-time equivalent skilled personnel would be required to cover three operating shifts per day.

2.5.10.1.5 Construction Phase Activities

To prepare for construction activities, the site would be cleared of ground cover and graded. Access roads and erosion control would be required during the construction phase of the project. Construction temporary facilities would include construction road and parking area construction and maintenance, installation of construction power, installation of construction water supply and general sanitary facilities, and general and miscellaneous labor services such as jobsite cleanup and construction of general safety and access items. For the commercial scale facility, two crew of six equipped with appropriate machinery would require approximately 20 days to prepare the site.

Additional construction activities would include building foundations for the major equipment and buildings, field erection of equipment, piping, instrumentation and control systems, and utility tie-ins (water, steam, electricity). These construction activities would require heavy machinery and a crew of around 400 personnel working for approximately 1.5 years.

Table 2-31. IGCC with CO_2 Recovery Model Project Data Sheet

Parameter	Description/Basis	Commercial Deployment Level
Description of Model Plant	Model plant is an integrated gasification process to produce syngas fuel from coal, with a combined cycle gas turbine plant for power generation. The syngas clean-up process operations include oxidation of CO to CO_2 in a gas water shift reaction, followed by acid gas removal process for separation and concentration of CO_2 and H_2S for compression, and potential resale for EOR operations.	
Plant Characteristics		
Net Capacity, MW	Based on expected size range. Net capacity based on gross generation less the parasitic load requirements of the plant.	520
Gross power, MW	Based on auxiliary power requirements estimated at 18% of gross generation.	637
Capacity Factor, %	Capacity factor range represents a low and high range for IGCC technology.	65 - 85
Syngas production rate, MMBtu/hr (HHV)	Based on heat rate of 9,300 Btu/kWh, HHV	4,836
Processes:	Coal is pulverized and fed as water slurry to gasification reactor, where it is entrained in 95% pure oxygen stream. The oxygen is separated from air in cryogenic process. Raw syngas stream from the gasifier is water-gas shift reacted to form CO_2. The CO_2 is removed, together with H_2S in an acid gas removal chemical absorption process. The CO_2/H_2S is separated from the rich solvent and is compressed and dehydrated for transport via pipeline.	
Major Equipment associated with CO_2 stream:	Gasifier, syngas cooler, candle filter, flare stack, water-gas shift reactors, waste heat recovery steam generators, raw gas coolers, absorber tower, amine solvent storage tanks, rich/lean heat exchanger, amine solvent regenerator/stripper, reboiler, condenser, pumps, blower, multi-stage intercooled compressor, glycol dehydrator	
Operating Utilities	Steam, electricity, cooling water, boiler feed water, chemicals makeup	
Plant Feed Rates		
Coal Feed Rate, lb/hr	Coal feedstock feed rate on dry basis, assuming heating value of coal is 11,700 Btu/lb, HHV and plant heat rate is 9,300 Btu/kWh, HHV	413,000

Parameter	Description/Basis	Commercial Deployment Level	
Water make-up, lb/hr	Water make-up for process, boiler feed, etc.	858,000	
Oxygen, lb/hr	Feed rate of 95% pure oxygen from the Air Separation Unit to the gasifier	338,000	
Recovered CO_2 Stream			
CO_2 recovered, lb/hr	CO_2 stream flow rate assuming 90% overall CO_2 capture.	764,000	
CO_2 recovered, MT/day	CO_2 stream flow rate assuming 90% overall CO_2 capture.	8,320	
CO_2 recovered, MT/Year		3,035,760	
H_2S recovered, lb/hr	H_2S mass balance assumes that all sulfur in the coal is recovered in the acid gas removal process (over 99 % efficient). H_2S concentration is based on high sulfur coal with sulfur content of 3 percent.	12,400	
H_2S concentration, wt %	Calculated based on mass rates of CO_2 and H_2S recovered.	2	
H_2S recovered, MT/year		49,275	
Utility and Chemical Requirements			
Steam (MMBtu/hr)	Steam requirements (e.g., amine regeneration reboiler) based on mid-range of 4.0 MMBtu/MT CO_2 recovered from published values (Chakravarti et al, 2001; Chinn et al, 2004; Morimoto, et al).	1,390	
Electricity (kW)	Based on difference between auxiliary electricity requirements for IGCC with CO_2 recovery (adjusted to exclude CO_2 compression) and IGCC without CO2 recovery (EPRI, Dec. 2000)	16,200	
Water make-up for CO_2 plant, gpm	For the CO_2 recovery operations, water make-up is based on 180 gpm required for 2,800 MT per day recovered CO_2.	535	
Solvent recirculation rate, gpm	Based on recirculation rate of 2.18 gal. MEA solution/lb CO_2 removed (Chinn et al, 2004)	27,760	
Solvent make-up, gpm	Based on 0.05% loss (Chinn et al, 2004)	14	
Soda Ash, lb/hr	Based on 168 kg/hr for a 4800 gpm solvent recirculation rate (Chinn et al, 2004)	2,140	
Air Emissions		**CO_2 capture only**	**Plant-wide**
CO_2, lb/hr	Mass rate based on 90 percent capture efficiency.	(787,260) decrease[5]	84,885 (10% not captured)[6]
SO_x, lb/hr	Mass rate based on projected emission levels shown in Table 3-33.	Net decrease[7]	57-364
NO_X, lb/hr	Mass rate based on projected emission levels shown in Table 3-33.	Negligible	130-400
CO, lb/hr	Mass rate based on projected emission levels shown in Table 3-33.	Negligible	166
PM, lb/hr	Mass rate based on projected emission levels shown in Table 3-33.	Negligible	52
VOC, lb/hr	Mass rate based on projected emission levels shown in Table 3-33.	Negligible	5
Wastes Generated			
Reclaimer Sludge, lb/hr	Based on 5000 MT/yr sludge for a 5,200 MT per day recovered CO_2 plant (Simmonds et al)	2,010	
Spent carbon, lb/hr	Based on 114 kg/day for 4800 gpm solvent circulation rate (Chinn et al, 2004)	60	

[5] Overall CO_2 emissions would represent net decrease over IGCC without CO_2 capture. Difference in emissions (i.e., net emissions decrease) is based on EPRI, Dec. 2000.
[6] Assumes IGCC with 90 percent CO_2 capture.
[7] Overall sulfur compound emissions would decrease due to the avoidance of downstream sulfur recovery operations. Emissions for both IGCC with CO_2 capture and without CO_2 capture are reported to be negligible, per EPRI, Dec. 2000.

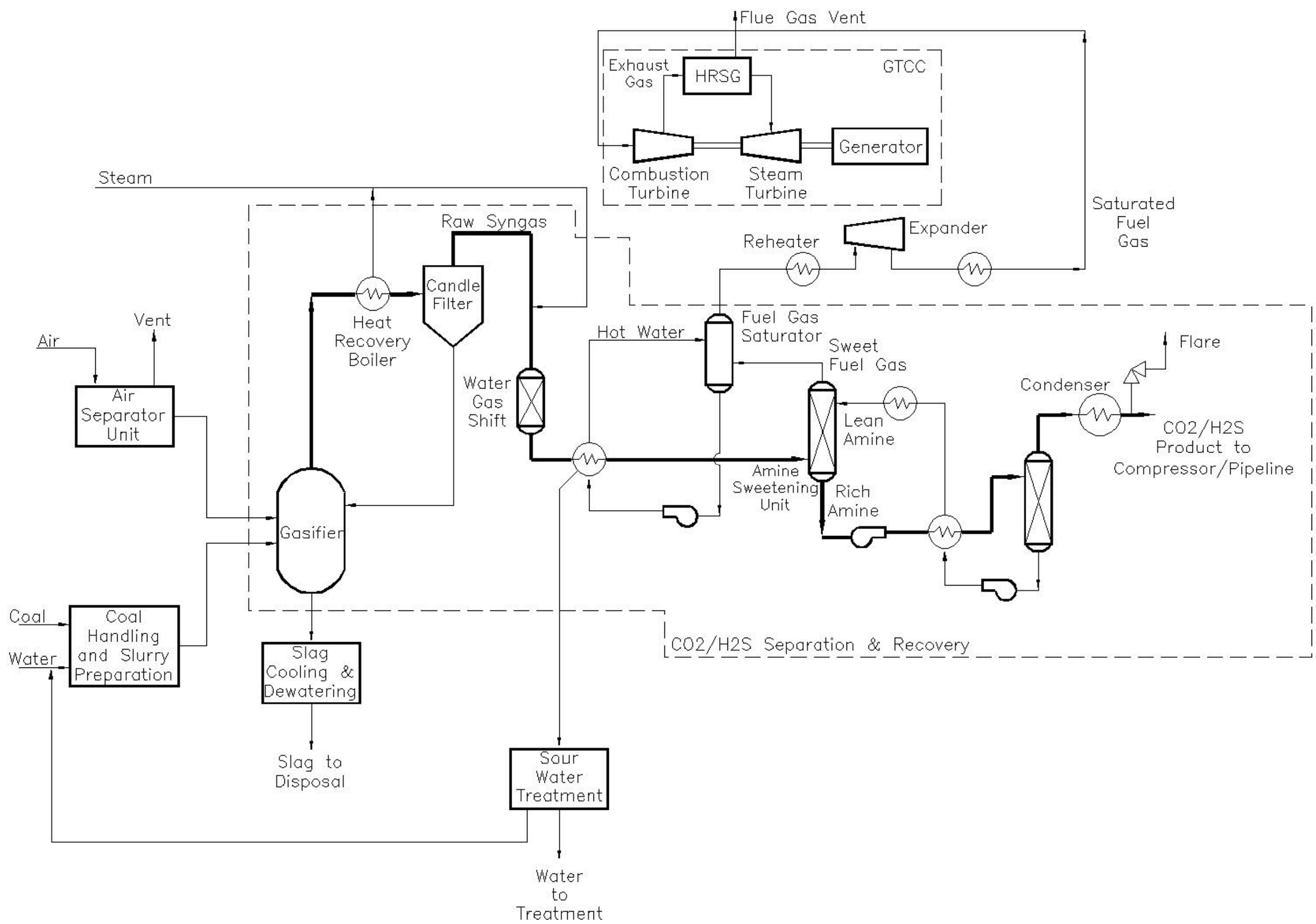

Figure 2-13. Schematic Diagram of IGCC with CO_2/H_2S Capture

2.5.10.2 Case B -- Sour Associated Gas Recovery and Re-Injection for Enhanced Oil Recovery (or Saline Formation CO_2 Sequestration/H_2S Disposal)

This model project case was developed to evaluate the environmental-related considerations associated with the separation, recovery, and re-injection of CO_2 and hydrogen sulfide H_2S in sour oil and gas fields. The model plant is based on capture of the sour associated gas during oil production, separation of the H_2S and CO_2 in a conventional acid gas removal process, and re-injection of the CO_2, with H_2S, for EOR operations. This process is similar to conventional sour gas treatment, except that the sulfur would typically be separated from the CO_2 and further processed as a byproduct stream, whereas the CO_2 would conventionally be vented to the atmosphere after removal from the natural gas stream. In the acid gas re-injection model plant case, the acid gases are re-injected into a suitable underground formation, thus eliminating the CO_2 emissions and the sulfur recovery operations.

In Western Canada, acid gas re-injection technology is operational in over 30 projects. The H_2S composition of the acid gas stream varies widely in these projects, ranging from: 2 percent H_2S in 95 percent CO_2 to 83 percent H_2S in 14 percent CO_2 (molar basis). Wellhead injection pressure varies between 3,750 to 19,000 kPa. Injection rates vary between 2,000 and 900,000 m^3/day for these projects in Canada. Acid gas re-injection is only recommended for sour gas formations where existing production equipment is designed to handle the corrosivity and safety concerns associated with H_2S in the gas. The long-term effects of acid gas re-injection on formation pressure, acid gas concentration build-up, permanence of CO_2 sequestration, and impacts on enhanced oil recovery are being researched.

2.5.10.2.1 General Design and Operating Parameters

Model Plant Process Description. The process flow for the associated sour gas recovery and re-injection model project case is illustrated in Table 2-14. The unit operations of focus for the model plant are those associated with the acid gas stream in the plant, including:

- 3-phase separation of gas, oil, and water;
- Amine acid gas removal; and
- Amine solvent regeneration and acid gas capture (Figure 2-14).

As shown in Table 2-14, produced fluids are transferred from the oil production wells to a centralized production facility using multi-phase pumps. The fluids may pass through a 3-stage lateral separator to meter the fractions of oil, water, and gas fractions, and metering stations are equipped with flares to provide safe release of scheduled and unexpected releases of gas or oil.

The produced fluids are separated into gas, oil and water fractions in a 3-phase separator. Oil may be treated in a heater-treater to flash off any volatile compounds in solution, with the flash gas recovered and added to the gas fraction from the separation process. The oil is desalinated and stabilized prior to transferring to stock tanks.

After the separation of any liquids, the produced sour gas stream is routed to an acid gas removal (AGR) unit using an amine or amine derivative as the solvent. The AGR unit is a counter-current gas absorber unit that contacts the sour gas stream with solvent to remove CO_2 and H_2S from the natural gas. The sweetened gas stream exiting the top of the AGR separator passes through an outlet separator to remove condensed water. The sweet gas may be further processed to separate propane and butane, depending on the gas composition, and the natural gas product is compressed and metered for sale.

The rich amine from the AGR absorber may be fed to an amine flash tank to release the absorbed volatile hydrocarbons. The flash gas is typically combusted in the amine regenerator reboiler or recycled back to the inlet of the amine absorber. Not all sweetening units are equipped with a flash tank. After the flash tank, the rich amine stream is filtered to remove solids and other contaminants. The rich amine stream is then passed through a heat exchanger for preheating before being fed to the top of the amine regenerator. In the regenerator, the amine solution is regenerated by stripping the CO_2 and H_2S from the rich solvent. The lean amine from the bottom of the regenerator is recycled back to the AGR separation unit, while the regenerator overhead stream, concentrated CO_2 and H_2S, is condensed to remove water, then compressed in multi-stage, intercooled compressors and dehydrated to supercritical conditions. This concentrated, H_2S-laden CO_2 stream is metered and transported via pipeline to the injection wells. The compression and pipeline operations are considered part of the model plant boundaries for the CO_2 transport model.

Model Project Design and Operating Parameters. Two model project sizes were selected for evaluation of the environmental considerations. Table 2-32 includes the model project design and operating parameters for the low and high capacity plants, respectively.

The recovered acid gas composition for the low capacity case represents the low range of H_2S concentration in recovered CO_2, based on the existing Canadian projects. The low capacity case is based on 2 wt% H_2S in 98 percent CO_2 at an injection rate compatible with the pilot EOR model project. This low capacity case would represent a slipstream from the regenerator overhead of an existing sour gas processing operation. The incremental requirements for capture of the CO_2/H_2S stream would entail additional piping, valves, instrumentation, and control system configuration at the model plant. The equipment required for compression and dehydration of the slipstream is assumed to be included as part of the CO_2 transport model plant.

For the case of the low capacity model plant, the existing sour gas production facility assumes that sour gas is separated from the hydrocarbon gas stream in a conventional amine AGR unit. The H_2S recovered in the amine regeneration cycle for the existing operations would be flared, incinerated, or sent to a sulfur recovery process. The CO_2 from the existing facility would be vented to the atmosphere. Therefore, the recovery of the slipstream from the amine regenerator overhead for the CO_2/H_2S capture model project would represent an overall savings, albeit small, in energy requirements and subsequent emissions from the existing project scenario.

Both CO_2 and H_2S form hydrates at temperatures up to 10 deg. C for CO_2 and more than 30 deg. C for H_2S, thus operation at temperatures above hydrate formation is a key design parameter. Methanol is often injected to prevent hydrate formation. Therefore, it is anticipated that a methanol chemical injection pump and storage facilities would also be an incremental requirement of the process operations for capturing the acid gas stream.

The high capacity case represents a reasonably high level of H_2S in CO_2 that would be considered appropriate for EOR injection purposes, as opposed to disposal. For model plant design purposes, the design is based on the average inlet H_2S and CO_2 concentrations for diethanolamine (DEA) AGR processes in gas plant duty in the U.S. (GRI, 1991). For DEA AGR processing at gas plants, the H_2S and CO_2 concentrations in the treated gas stream are 1.7 and 4.1 mole percent, respectively, which relates to a concentrated CO_2 stream downstream of the amine regenerator containing 25 percent by weight H_2S.

As in the low capacity model plant case, the existing facility is assumed to be a gas production/processing site that previously recovered sulfur in a sulfur recovery operation and vented CO_2 to the atmosphere.[8] For converting the facility to capture and recover CO_2 and H_2S for reinjection, the only process changes required would be additional piping, valves, instrumentation, and control system configuration for regenerator overhead gas rerouting, addition of a methanol chemical injection pump and injection point for hydrate formation inhibiting, and reduction in or shut down of the existing sulfur recovery operations. Therefore, the recovery of the stream from the amine regenerator overhead for the CO_2/H_2S capture model project would represent an overall savings in energy requirements and subsequent emissions from the existing project scenario.

2.5.10.3 Utility Requirements

Utility requirements included in Table 2-32 are for the CO_2 recovery steps of the sour gas production operations. For the separation process, electricity is required to operate the solvent pumps, coolers, and instrumentation. However, the CO_2/H_2S separation process is considered existing equipment in place for conventional sour gas production. Only in the case of additional capacity in the model plant scenario is there an increase in electricity consumption for CO_2/H_2S separation.

It is likely that electricity consumption for the CO_2/H_2S capture model project would represent an overall net decrease over existing facility operations. This decrease in electricity usage is due to the avoidance of downstream sulfur recovery operations, such as Claus plant treatment and incineration. It should be noted that the energy requirements for CO_2/H_2S compression are not included in the estimates provided in Table 2-32, as they are included in the separate CO_2 transport model project.

Steam is also required for CO_2/H_2S separation operations, but the incremental steam requirement for the model plant is not expected to increase over the existing facility operations. Likewise, water make-up rates are not anticipated to increase over the existing facility operations. Even solvent recirculation rates

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[8] For the high capacity model plant, even in an unlikely scenario where sour gas production operations are considered new plant, the design of the system to handle H_2S would require the installation of an amine AGR process for the oil/gas production baseline operations, even without recovery of the CO_2/H_2S stream for EOR. Therefore, even for a greenfield site application, the acid gas stream recovery for EOR would represent minimal incremental plant modifications.

and solvent loss is not expected to show an incremental increase over the existing operations at the facility.

The only additional consideration for the model plant scenario is the injection of methanol into the recovered CO_2/H_2S stream to prevent hydrate formation during the downstream compression, transport, and injection operations.

2.5.10.4 Environmental Process Discharge Streams

For the CO_2/H_2S capture model plant, the basis of the evaluation is comparison to existing operations in a typical sour gas production or processing facility. As such, the environmental aspects of the model plant project activities would include avoidance of the energy requirements and emissions associated with the partial bypass and/or shutdown of the sulfur recovery operations. The most significant environmental aspect of CO_2/H_2S capture is the avoidance of previously vented CO_2 emissions from the gas production or processing operations. The model project will not result in increases in pollutant air emissions.

Note that the CO_2 stream compression operations are considered part of the model plant boundaries for the CO_2 transport model. Therefore, any environmental considerations, such as combustion emissions associated with gas-driven compression, would be considered in the CO_2 transport model plant and not included here.

2.5.10.5 Site Requirements and Operations

The CO_2 recovery process would require construction of additional piping, instrumentation, and controls. A methanol chemical injection pump is also required in pipe layout to inject methanol into the recovered acid gas stream for hydrate formation inhibiting. As such, only minor equipment, with no major equipment required, is anticipated for the plant modifications needed to integrate the acid gas capture design. Compression and dehydration operations are included in the adjacent CO_2 transport model plant.

Based on the equipment recovered for the acid gas recovery operations at the oil and gas production facility, the model project is expected to require about 1-15 acres of land. No additional access roads are required. To maintain operations of the facility, 3-6 full time skilled personnel would be required.

2.5.10.6 Construction Phase Activities

To prepare for construction activities, the site would be cleared of ground cover and graded. Access roads may be required during the construction phase of the project. General and miscellaneous labor services such as jobsite cleanup and construction of general safety and access items would be included.

Construction activities would include field erection of piping, instrumentation and control systems. For the pilot and commercial scale facilities, one or two crews of three would take 5-10 days, respectively, to prepare the site. Construction activities would require 50-200 personnel 6-12 months to complete construction.

Table 2-32. Sour Associated Gas Recovery and Reinjection Model Project Data Sheet

Parameter	Description/Basis	Low	High
Description of Model Plant	Model plant is a sour oil and gas production operation, with removal and recovery of the CO_2 and H_2S in the gas stream for re-injection operations.		
Plant Characteristics			
CO_2/H_2S recovery capacity, MMscfd	Based on expected size range. For a low capacity plant, recovery of a slipstream with equivalent flow to supply one injection well with 0.23 MMscfd would be assumed. For the high capacity plant, the assumed volumetric throughput is sufficient to supply 35 injection wells with 1.05 MMscfd per well.	0.23	35
H_2S content of recovered CO_2 stream, wt %	Low case based on Canadian projects. High case is based on average H_2S to CO_2 ratio for DEA separation in U.S. gas plants. High case also represents realistic maximum H_2S concentration, above which sour gas co-sequestration would be impractical from a geologic CO_2 sequestration perspective.	2	25
Total average H_2S recovered, MT/yr	Calculated based on average molecular weight of H_2S/CO_2 mixture, and the fraction of H_2S.	100	182,400
Total average CO_2 recovered, MT/yr	Calculated based on average molecular weight of H_2S/CO_2 mixture, and the fraction of CO_2.	4,300	547,100
Processes:	The acid gas stream is separated from oil and produced water in a 3-phase separator. The CO_2 is removed from the acid gas stream, together with H_2S, in an acid gas removal chemical absorption process. The CO_2/H_2S is separated from the rich solvent and is supplied for enhanced oil recovery injection.		
Major Equipment associated with CO_2 stream:	AGR absorber tower, amine solvent storage tanks, rich/lean heat exchanger, amine solvent regenerator/stripper, reboiler, condenser, pumps, blower. (Note: Multi-stage, intercooled compressor, glycol dehydrator are included in CO_2 transport model plant.)		
Operating Utilities	Steam, electricity, cooling water, chemicals makeup		
Utility and Chemical Requirements			
Steam (MMBtu/hr)	Steam requirements (e.g., amine regeneration reboiler) are not anticipated to change over existing production operations.	Negligible	Negligible
Electricity (kW)	Net decrease in overall electricity requirements due to shut-down or avoidance of downstream sulfur recovery operations	Net decrease	Net decrease
Water make-up for CO_2 plant, gpm	For the CO_2 recovery operations, water make-up is not expected to change over existing production operations.	Negligible	Negligible
Solvent make-up, gpm	For the CO_2 recovery operations, solvent make-up rates are not expected to change over existing production operations.	Negligible	Negligible
Soda Ash, lb/hr	For the CO_2 recovery operations, soda ash and other chemical additives (e.g., foam inhibitors, corrosion inhibitors) are not expected to change over existing production operations.	Negligible	Negligible
Air Emissions			
CO_2, lb/hr	Net decrease in CO_2 emissions to the atmosphere.	(1,095)	(166,600)
SOx, lb/hr	Slight decrease in overall SOx emissions is anticipated due to H_2S recovery and avoidance of downstream sulfur recovery operations.	Net decrease	Net decrease
Wastes Generated			
Regenerator Sludge, lb/hr	For the CO_2 recovery operations, regenerator sludge generation/disposal rates are not expected to change over existing production operations.	Negligible	Negligible
Spent carbon, lb/hr	For the CO_2 recovery operations, spent carbon rates are not expected to change over existing production operations.	Negligible	Negligible

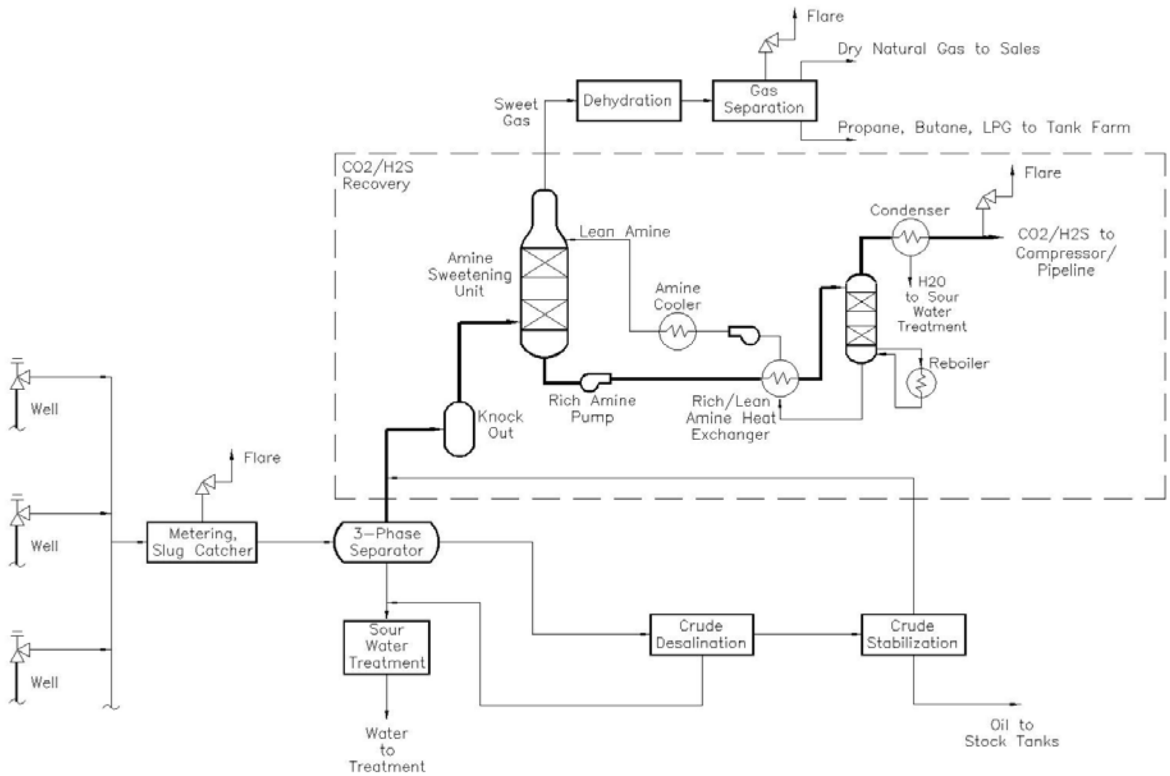

Figure 2-14. Schematic Diagram of Sour Associated Gas CO_2/H_2S Capture

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2.6 MODEL PROJECT SUMMARY TABLES

2.6.1.1 Carbon Sequestration

Table 2-33 provides a summary of the individual projects rates of CO_2 capture, transport or sequestration in metric tons (MT).

Table 2-33. Summary of Carbon Sequestration Rates per Model Project

Technology/Project Type	CO_2 Captured, Transported or Sequestered per Project (Field Validation-Scale, MT/Year)	CO_2 Captured, Transported or Sequestered per Project (Commercial-Scale, MT/Year)
Post-Combustion CO_2 Capture	74,825	2,238,910
CO_2 Compression and Transport (trucking)	36,500	0
CO_2 Compression and Transport (pipeline)	0	910,600
Coal Seam Sequestration	11,680	910,600
Enhanced Oil Recovery (EOR) Sequestration	4,380	809,209
Saline Formation Sequestration	13,140	909,100
Basalt Formation Sequestration	2,720	453,600
Terrestrial –Forestation Sequestration	3,630	90,720
Co-Sequestration CO_2/H_2S Capture: IGCC Based	0	3,036,800
Co-Sequestration CO_2/H_2S Capture: Sour Gas Associated for EOR or Saline Formation	4,380	547,500

2.6.1.2 Land Requirements

Table 2-34 provides a summary of the land requirements and how much land would be disturbed by individual projects at the field validation-scale and commercial-scale.

Table 2-34. Summary of Land Requirements and Disturbance per Project

Technology/ Project Type	Total Project Acreage per Project (Field Validation-Scale)	Total Project Acreage Disturbed per Project (Field Validation-Scale)	Total Project Acreage per Project (Commercial-Scale)	Total Project Acreage Disturbed per Project (Commercial-Scale)
Post-Combustion CO_2 Capture	5	5	60	60
CO_2 Compression and Transport (trucking)	0	0	0	0
CO_2 Compression and Transport (pipeline)	3.5	3.5	141	141
Coal Seam Sequestration	90	19	1,500	244
Enhanced Oil Recovery (EOR) Sequestration	135	15	2,880	686
Saline Formation Sequestration	92	9	2,750	291
Basalt Formation Sequestration	59	16	2,600	166
Terrestrial –Forestation Sequestration	500	0	10,000	0
Co-Sequestration CO_2/H_2S Capture: IGCC Based	0	0	30	30
Co-Sequestration CO_2/H_2S Capture: Sour Gas Associated for EOR or Saline Formation	1	1	15	15

2.6.1.3 Operational Chemical Requirements

Table 2-35 provides a summary of the annual chemical requirements for individual projects at the field validation-scale and commercial-scale. Rates of chemical use per metric ton of CO_2 captured and transported are provided in Table 2-36.

Table 2-35. Summary of Chemical Requirements per Project

Technology/ Project Type	Aqueous Solvent (gal/year) per Project (Field Validation-Scale)	Aqueous Solvent (gal/year) per Project (Commercial-Scale)	Soda Ash (lbs/year) per Project (Field Validation-Scale)	Soda Ash (lbs/year) per Project (Commercial-Scale)	Lubricating Oil (gal/year) per Project (Field Validation-Scale)	Lubricating Oil (gal/year) per Project (Commercial-Scale)
Post-Combustion CO_2 Capture	181,040	5,430,470	464,280	18,937,160	0	0
CO_2 Compression and Transport (trucking)	0	0	0	0	438	0
CO_2 Compression and Transport (pipeline)	0	0	0	0	0	56,940
Co-Sequestration CO_2/H_2S Capture: IGCC Based	0	7,295,255	0	18,746,400	0	0

Table 2-36. Chemical Use per Metric Ton of CO_2 Captured or Transported

Technology/ Project Type	Aqueous Solvent Use per MT CO_2 Captured/ Transported (Gal/MT)	Soda Ash Use per MT CO_2 Captured/ Transported (lbs/MT)	Soda Ash Use per MT CO_2 Captured/ Transported (lbs/MT)
Post-Combustion CO_2 Capture	2.4	8.5	*NA*
CO_2 Compression and Transport (trucking)	NA	NA	*0.01*
CO_2 Compression and Transport (pipeline)	NA	NA	*0.06*
Co-Sequestration CO_2/H_2S Capture: IGCC Based	2.4	6.2	*NA*

Note: All based on commercial-scale project except for Compression and Transport by Trucking

2.6.1.4 Well Installation

Table 2-37 provides a summary of the well installation requirements for individual projects at the field validation-scale and commercial-scale.

Table 2-37. Summary of Injection and Monitoring Wells Installed per Project and Alternative

Technology/Project Type	Injection Wells per Project (Field Validation-Scale)	Monitoring Wells (Field Validation-Scale)	Injection Wells per Project (Commercial-Scale)	Monitoring Wells per Project (Commercial-Scale)
Coal Seam	1	1	12	8
Enhanced Oil Recovery (EOR)	1	1	35	20
Saline Formation	1	1	3	8
Basalt Formation	1	3	12	10

Note: Additional production wells would also be installed for related resource recovery, such as under ECBM, EOR, EGR.

2.6.1.5 Waste Generation

Table 2-38 and Table 2-42 provide summaries of wastes (used oil, well cuttings, wastewater, sludge, and spent carbon) generated by individual projects at the field validation-scale and commercial-scale. The tables also summarize the collective amounts of the wastes generated under each alternative. Table 2-40 provides a comparison of wastes generated for each process relative to the amount of CO_2 captured, transported or sequestered.

Table 2-38. Oil and Well Drillings Generated Per Project and Alternative

Technology/ Project Type	Used Oil (gal/year) per Project (Field Validation-Scale)	Used Oil (gal/year) per Project (Commercial-Scale)	Well-Drill Cuttings (cu. Ft) per Project (Field Validation-Scale)	Well-Drill Cuttings (cu. Ft) per Project (Commercial-Scale)
CO_2 Compression and Transport (trucking)	120	0	0	0
CO_2 Compression and Transport (pipeline)	0	5,640	0	0
Coal Seam	2.98	59.5	3,472	34,920
Enhanced Oil Recovery (EOR)	0	0	4,800	268,000
Saline Formation	0	0	4,200	58,800
Basalt Formation	0	0	4,200	38,400

Table 2-39. Wastewater, Sludge and Carbon Waste Generation Per Project and Alternative

Technology/ Project Type	Wastewater (gal/hour) per Project (Field Validation-Scale)	Waste-water (gal/hour) per Project (Commercial-Scale)	Reclaimer Sludge (lbs/hr) per Project (Field Validation-Scale)	Reclaimer Sludge (lbs/hr) per Project (Commercial-Scale)	Spent Carbon (lb/hr) per Project (Field Validation-Scale)	Spent Carbon (lb/hr) per Project (Commercial-Scale)
Post-Combustion CO_2 Capture	0	0	50	1,485	1.5	45
CO_2 Compression and Transport (pipeline)	24	348	0	0	0	0
Co-Sequestration CO_2/H_2S Capture: IGCC Based	0	0	0	2,010	0	60
Coal Seam	2.98	59.5	0	0	0	0

Table 2-40. Wastes Generated Per Metric Ton CO_2 Captured/Transported/Sequestered

Technology/ Project Type	Used Oil Generated per MT CO_2 Captured/ Transported/ Sequestered (gal/MT)	Wastewater Generated per MT CO_2 Captured/ Transported/ Sequestered (gal/MT)	Reclaimer Sludge Generated per MT CO_2 Captured/ Transported/ Sequestered (lbs/MT)	Spent Carbon Generated per MT CO_2 Captured/ Transported/ Sequestered (lbs/MT)
Post-Combustion CO_2 Capture	0	0	54.4	*0.2*
CO_2 Compression and Transport (trucking)	0.003	0	0	*0*

Technology/ Project Type	Used Oil Generated per MT CO_2 Captured/ Transported/ Sequestered (gal/MT)	Wastewater Generated per MT CO_2 Captured/ Transported/ Sequestered (gal/MT)	Reclaimer Sludge Generated per MT CO_2 Captured/ Transported/ Sequestered (lbs/MT)	Spent Carbon Generated per MT CO_2 Captured/ Transported/ Sequestered (lbs/MT)
CO_2 Compression and Transport (pipeline)	0.006	3.3	0	*0*
Co-Sequestration CO_2/H_2S Capture: IGCC Based	0	0	5.8	*0*
Coal Seam	<0.0001	0	0	0

2.6.1.6 Air Emissions

Table 2-41 provides a summary of air emissions associated with compression and transport of CO_2. Heating units associated with injection of CO_2 at geologic sequestration sites also generate air emissions. These rates are summarized in Table 2-42.

Table 2-41. Air Emissions Relating to Compression and Transport Options

Parameter	Compression and Trucking (lb/hour)	Compression and Pipeline (lb/hour)	Trucking (lbs/MT CO_2 conveyed)	*Pipeline (lbs/MT CO_2 conveyed)*
CO_2	315	17,190	37.8	*165.4*
CO	1.90	60	0.23	*0.57*
CH_4	2.31	227	0.28	*2.18*
NOx	5.3	495	0.64	*4.76*
VOC	*0.2*	*19*	*0.02*	*0.18*

Table 2-42. Air Emissions Relating to Heating Units at Sequestration Sites

Parameter	Coal Seam, Field Validation-Scale (lbs/hour)	Coal Seam, Commercial-Scale (lbs/hour)	Saline Formation, Field Validation-Scale (lbs/hour)	Saline Formation, Commercial-Scale (lbs/hour)
CO_2	7.3	576.7	8.4	*587.2*
CO	<0.01	0.13	<0.01	*0.13*
CH_4	<0.01	0.01	<0.01	*0.01*
NOx	0.01	0.52	0.01	*0.63*
VOC	<0.01	0.01	<0.01	*0.02*
PM	<0.01	0.05	<0.01	0.05

2.7 REGULATORY FRAMEWORK AND PERMITTING

While large numbers of federal regulations in the U.S. deal with air emissions from industrial and energy generation facilities, to date none of these U.S. regulations currently govern CO_2 emissions into the atmosphere. Only the inventory list for the Toxic Substances Control Act (TSCA) of 1976, the NIOSH confined space hazard classification system, and the Federal Emergency Management Agency's (FEMA) hazardous materials guide treat CO_2 as a hazardous substance to the extent that any concentrated, pressurized, or cryogenic gas poses a danger. In all cases, it is included in the least hazardous category (Benson, 2002).

Federal and state authorities regulate CO_2 for many different purposes, including occupational safety and health, ventilation and indoor air quality, confined-space hazard and fire suppression, transportation, as a respiratory gas and food additive, and for animal anesthesia. Federal occupational safety and health regulations set three limits:

- 0.5 percent or 5,000 ppm for an average 8-hour day or 40-hour week.
- 3 percent or 30,000 ppm for an average short-term 15-minute exposure limit.
- 4 percent or 40,000 ppm for the maximum instantaneous exposure limit above which is considered immediately dangerous to life and health.

Most industrial and safety regulations for CO_2 focus on engineering controls and specifications for transportation, storage containers, and pipelines. Surface risks of CO_2 exposure are typically handled by State environmental health and safety regulatory agencies (Benson, 2002).

Some examples of federal agencies having codes of federal regulations (CFRs) relating to CO_2 include the following (Benson, 2002):

- Office of Pipeline Safety (OPS): gas or hazardous liquid regulations for engineering safety controls on pipelines.
- Department of Transportation (DOT): general requirements for transportation of materials.
- Occupational Safety and Health Administration (OSHA): air contaminant exposure limits, compressed breathing gas limits, confined space hazards environmental controls, and fire suppressants engineering controls and employee training.
- Mine Safety and Health Administration (MSHA): air contaminant exposure limits for underground and surface mines.
- National Institute of Occupational Safety and Health (NIOSH): compressed breathing gas limits for respirators and self-contained breathing apparatus.
- Federal Aviation Administration (FAA): ventilation air contaminant in airplane cabins.
- Food and Drug Administration (FDA): food substance and medical gas requirements.

Although CO_2 is not regulated at the federal level as an air emission, and other federal regulations are somewhat limited and generally focused on specific CO_2 applications, as described above, there are a number of key pieces of existing federal legislation that could affect carbon sequestration projects overall. Some of these may include, but are not limited to, the following:

- Clean Water Act (CWA, 1977): Sets the standard of nondegradation of the beneficial uses of water. Requires control of oxygen-demanding organic matter and suspended solids in the effluents discharged (as wastewater) from point and non-point sources. Uses area control or performance standards, such as requiring Best Management Practices, or operational activities to minimize impacts to water quality.

- Safe Drinking Water Act (SDWA, 1974): Led to EPA's Underground Injection Control (UIC) Program, setting requirements for different class injection wells. Of the five classes of wells according to regulations established by the federal UIC program, Class I wells are the most stringent and refer to injection of municipal or industrial waste, including hazardous waste, below the deepest underground sources of drinking water.
- Clean Air Act (CAA, 1970, 1990): Programs issue permits for new (and in some cases existing) stationary sources of emissions so that the emissions will not exceed the national ambient air quality standards (NAAQS) set for the six criteria pollutants: sulfur dioxide, particulate matter, nitrogen dioxide, carbon monoxide, ozone (and its precursors, nitrogen oxides and volatile organic compounds), and lead. Establishes New Source Review, New Source Performance Standards, hazardous air pollutant standards, operating permits, and acid rain controls. (Note: Although CO_2 is not a regulated pollutant in the CAA, there are other regulated pollutants associated with carbon sequestration projects, primarily in the capture and transmission segments, that could be affected by the CAA.)

The current regulatory structure for underground injection combines together the efforts of many different agencies and regulatory authorities. Many different federal and state regulations and agencies are charged with ensuring that materials are handled, transported, and injected in a safe and appropriate manner. Pipeline transport is regulated by the Department of Transportation, for instance, while many of the EHS regulations are set by OSHA and adopted and enforced by the states.

2.7.1 Underground Injection Control (UIC) Program

Underground injection activities on land and in state waters are regulated by the U.S. EPA, with primacy given to different state agencies. Permitting requirements vary by individual well class. The explicit goal of the UIC program is to protect current and potential sources of public drinking water. The movement of injectate into an Underground Source of Drinking Water (USDW) is explicitly prohibited in Class I and II wells, where a USDW is defined as an aquifer that has a total dissolved solids content of less than 10,000 mg/L (Brasier, 1996). UIC regulations do not, with the exception of hazardous waste Class I wells, specify any containment time for the injectate (Wilson, 2003).

Even within the same jurisdiction, the injection of identical fluids is treated differently, depending on their source. Produced brine from a hydrocarbon production operation and that from an industrial process fall under different well classes; are managed by different institutions; and are subject to different site characterization, construction, management, and reporting requirements. It is unclear now if CO_2-specific regulations would be integrated within the existing underground injection regulations or if, in the long run, an entirely different regulatory approach would be beneficial (Wilson, 2003)

Federal jurisdiction to regulate underground injection in the U.S. was established by the 1974 Safe Drinking Water Act. On land in the U.S., underground fluid injection is managed under the U.S. EPA's UIC program. The structure of regulations that currently govern underground injection activity consists of an overarching federal program, laid out in detail in 40 CFR 144-148. In states without UIC primacy, the EPA Regional Offices manage the programs. In several states, additional regulatory controls that are specific to local geology or operational practices are applied to specific injection practices, making particular states more restrictive than the minimum federal standards. The federal code divides injection wells into five specific classes based on where the injectate originates, the level of potential health and environmental harm, and where it is to be injected. Depending on the well class, different state agencies manage the permitting and monitoring of injection activities.

> The explicit goal of the UIC program is to protect current and potential sources of public drinking water.

Class I wells handle non-hazardous industrial wastes as well as hazardous industrial wastes and municipal waste waters. The state's department of the environment usually manages them. Class I hazardous wells are required to obtain a "no migration demonstration" as required by the Resource Conservation and Recovery Act. Class II wells handle wastes associated with hydrocarbon production and enhanced oil recovery and are, with few exceptions, managed by the state's department of oil and gas. In practice, depending on their source and specific regulatory exemptions, similar wastes are injected into both Class I and II wells, but with quite different permitting and operational requirements. H_2S injected in a Class I regime is considered a hazardous waste, but within a Class II regime, H_2S arising from natural gas extraction is not. State EH&S regulations, such as Texas' Rule 36, ensure that safety considerations are incorporated into acid gas injection (Wilson, 2004)

While the Class I Hazardous Program may be run through the state, operators of hazardous waste wells must receive approval of a "no-migration demonstration", as required by RCRA and granted through the regional EPA office in addition to their state or U.S. injection permit (Smith, 1996). The rules mandate zero contamination: if "movement of any contaminant into the USDW" is detected, corrective actions will be taken "as are necessary to prevent such movement" (40 CFR 144.12b). The no-migration petition requires operators to demonstrate using computational models that wastes will not migrate from the injection zone for at least 10,000 years, or will be rendered harmless, as demonstrated through chemical transformation modeling (Wilson, 2003).

Aside from prescribed well integrity tests, the current regulatory structure for underground injection is almost exclusively procedural rather than performance-based. That is, the regulations specify what an operator must do; for example, they specify how an injection well must be constructed rather than specifying and outcome, such as a maximum acceptable leak rate that must be achieved. There are no federal requirements for monitoring the actual movement of fluids within the injection zone, nor are there requirements for monitoring in overlying zones to detect leakage, with the exception of specific Class I hazardous wells, where this monitoring can be but rarely is specifically mandated.

While there have been few reported problems, it is difficult to assess the success of the program because there is little monitoring designed to assess the transport of injected fluids. Therefore, there are no studies comparing the fluid transport predictions made in the no-migration petitions with actual observations (Wilson, 2003).

In March 2007, EPA issued Final Guidance to assist EPA Regional and State and Tribal Underground Injection Control (UIC) Program Directors in processing permit applications for pilot projects designed to evaluate the technical issues associated with CO_2 injection as Class V experimental technology wells. The aim of this Final Guidance is to assist UIC Program Directors in evaluating permit applications and setting appropriate Class V experimental technology well permit conditions for pilot CO_2 injection projects (EPA, 2007).

Permits for pilot CO_2 geologic sequestration projects will be issued by State, Tribal, and EPA Regional UIC Program Directors under the authority of the Safe Drinking Water Act (SDWA) beginning by March 2009 for the validation phase. EPA expects that commercial-scale geologic sequestration efforts will commence around 2012 for the deployment phase (EPA, 2007).

In the Final Guidance, EPA determined that CO_2 geologic sequestration wells constructed and operated as part of either phase may qualify as Class V experimental technology wells provided they meet the definition of that term in 40 CFR 146.3 ("a technology which has not been proven feasible under the conditions in which it is being tested"). Class V experimental technology wells are intended to demonstrate unproven but promising technologies with the rationale that allowing the use of these wells encourages innovation. Under EPA's regulations an injection well that is being used to demonstrate a developing technology may be subject to more flexible, yet fully protective, technical standards than those designed for commercially operating facilities. While injection of fluids, including CO_2 into the subsurface, e.g. for EOR and EGR, is a long-standing practice, injection of CO_2 for geologic sequestration is an experimental application of this existing technology (EPA, 2007).

Depending on the specific circumstances, for purposes of the pilot projects, permitting CO_2 injection into deep saline formations, depleted hydrocarbon reservoirs, or basalt formations through Class V experimental technology wells may be appropriate. In addition, depending on the particular facts, CO_2 injection wells of pilot geologic sequestration projects that involve methane-depleted coalbeds, depleting natural CO_2 formations, and non-commercial gas fields may be appropriate for permitting as Class V experimental technology wells. CO_2 injection for EOR or EGR operations is a long-established technology, and these wells may continue to be permitted as Class II wells, and Class II permitting requirements would apply. However, if the injection of CO_2 through those wells is not associated with the enhanced recovery of oil or gas, these operations would then be considered for re-permitting as Class V experimental technology wells (EPA, 2007).

Although there are no Federal requirements written specifically for Class V experimental technology wells, there are applicable requirements for Class V wells generally (see 40 CFR 144.12, 144.24 to 144.27, and 40 CFR 144.79-.89). Federal UIC permitting requirements at 40 CFR Parts 144 and 146 should be considered and implemented and permit issuers should follow the requirements for public participation (40 CFR Part 124) (EPA, 2007).

2.7.2 Pipeline Regulations and Permitting

In the U.S. Department of Transportation (DOT), PHMSA - the Pipeline and Hazardous Materials Safety Administration has public responsibilities for safe and secure movement of hazardous materials to industry and consumers by all transportation modes, including the nation's pipelines.

CO_2 pipelines are regulated as hazardous liquids pipelines. Federal regulatory approval is not ordinarily required for development of a new hazardous liquids pipeline, unless it will cross federal lands. Generally, state and local laws are the primary regulatory factors for construction of new hazardous liquid pipelines.

Types of permits that may be required for the construction of a CO_2 pipeline may include (but not limited to):

- State permit to operate and maintain a Hazardous Liquid Pipeline
- Wetland disturbance – under the Section 404 of the Clean Water Act. Pipelines that cross wetlands may qualify for the Nationwide-12 program.
- Air permits - Pumping Stations and Compression Stations are likely to require state air permits.
- NPDES permit – for stormwater related to construction activities.
- Soil Conservation – any local or state soil conservation district permits.
- Cross-border permit - the Secretary of State has the authority to issue Presidential Permits for cross-border liquid (water as well as petroleum product) pipelines and other cross-border infrastructure. The Office of International Energy and Commodity Policy receives and processes permit applications.

2.7.2.1 Pipeline Rights of Way

Most hazardous liquid and natural gas transmission pipelines are located underground in rights-of-way (ROW). A ROW consists of consecutive property easements acquired by, or granted to, the pipeline company. The ROW provides sufficient space to perform pipeline maintenance and inspections, as well as a clear zone where encroachments can be monitored and prevented.

The term “right(s)-of-way (ROW)” is used to describe the property or easement that pipeline operators secure in order to locate and maintain their pipeline. Operators generally obtain ROW by purchasing the property or acquiring an easement, by mutual negotiated agreement with a landowner, or through court-ordered condemnation procedures. Condemnation procedures are only carried out when specific types of pipelines are deemed by the courts to be necessary for public convenience.

2.7.2.1.1 ROW Agreements

ROW agreements typically specify the rights of the pipeline operator with respect to the property, as well as the ongoing above-ground use rights of the landowner. Additionally, ROW agreements may address issues such as:

- Single or multiple pipeline rights;
- Defined ROW width, which can vary from as small as the width of the pipeline to 50-feet or more;
- Rights for above ground facilities attached to the pipeline such as valves;
- Pipeline repair or modification constraints or considerations;
- Payment for original and continued use of the ROW;
- Damage award amounts appropriate for the property owner associated with original construction or future repairs/modifications;
- Access requirements for pipeline personnel, and;
- Requirements for pipeline removal upon termination of use by the pipeline operator.

2.7.2.1.2 ROW Special Considerations

A ROW is ordinarily sufficient for day-to-day operations of a pipeline, but is often insufficient for situations where pipeline repairs or expansions are planned. In such cases, the pipeline operator often has to renegotiate with a property owner for additional permanent and/or temporary work space.

Pipeline operators generally try to keep the ROW as free of physical encumbrances as possible in order to assure reasonable and frequent visual inspections of the pipeline from the air and ground. In addition, a clear ROW helps ensure ease of access for repair excavations.

These concerns must be balanced with the wishes of the landowner to maintain options for the ROW, including using the land for crops, grazing, parking and other uses. Limitations sometimes imposed on the landowner can include prohibitions against the installation of buildings, pools, trees and other physical structures.

Residential and commercial development in once-rural areas is encroaching on pipeline ROWs with increasing frequency. Encroachment implies safety concerns for local residents and for the physical integrity of the pipeline itself. To help prevent encroachment and excavation-related damage to pipelines, operators are required to post pipeline markers clearly and frequently along the length of the ROW. They must also communicate with residents along the ROW and establish liaison with local government and emergency officials (OPS, 2005).

2.7.2.2 Pipeline Safety Responsibilities

Pipeline operators are responsible for the assurance and management of safety in the operation of their energy transportation pipelines. Ensuring safety requires that operators consider every aspect of their pipeline operations, including:

- sound system design;
- selection and use of qualified materials;

- proper construction;
- thorough and adequate inspection, testing, maintenance and repair;
- continuous system monitoring and control;
- operations conducted by trained and qualified workers;
- implementation of damage prevention best practices;
- identification and mitigation of risks; and
- coordination and preparation for emergency response (OPS, 2005).

More information about the safety responsibilities of pipeline operators can be found at the Office of Pipeline Safety website at http://primis.phmsa.dot.gov/comm/SafetyResponsibilities.htm.

2.7.3 Coal Seam Sequestration Permitting Requirements

Given the large volumes of water associated with coal bed methane production and enhanced coal bed methane recovery from mineable coal seams, the water supply, treatment, and discharge aspects of a coal seam sequestration project will entail a significant portion of the project's permitting requirements. Some examples of the types of federal, state, and local water permits that may be required include the following (Montana DEQ, 2006):

- Section 404 of the Clean Water Act: discharge of dredged or fills material into the waters of the U.S..
- Clean Water Act, 33 USC 1341 Chapter 26: water pollution prevention and control.
- State water quality discharge permits.
- State Pollutant Discharge Elimination System (SPDES) permits: effluent guidelines limitations.
- State ground water pollution control system permit: facility-specific industrial dischargers.
- Surface water standards and procedures: rules.
- Mixing zones in surface and groundwater: rules.
- Nondegradation of water quality: rules.
- Short-term water quality standards for turbidity related to construction activity: permit.
- 401 Certification of USACE 404 permits.
- State permit for formation or off-channel containment pits storage of CBM produced water.
- State CBM general permits for temporary discharges for drought relief, and ground water quality characterization.
- State controlled groundwater area standards: production well standards, well log reports, water mitigation agreements, and groundwater monitoring and reporting requirements.
- State permit to appropriate groundwater.
- State permit for aquifer storage and retrieval wells.
- Water rights: issued by state natural resources agency, for beneficial uses of water from CBM operations.
- Local conservation district permits.
- Permit for proposed work in state streams, lakes, and wetlands.

In addition to the ground water and surface water potential permitting requirements associated with enhanced coal bed methane geologic sequestration projects, the other major permitting focus would likely be on the underground CO_2 injection. As discussed previously in Section 2.6.1, the Federal Safe Drinking Water Act established the UIC program to provide safeguards so that injection wells do not endanger current and future underground sources of drinking water. The EPA has the authority to control underground drinking water sources, with a majority of states having primacy for issuing UIC permits.

Injection wells related to oil and gas operations are known as Class II wells. Class II wells are those wells utilized for injection for the purpose of: a) enhanced recovery of oil and gas; b) injection for storage of hydrocarbons liquid, at standard temperature and pressure; and c) the disposal of fluids which are brought to the surface in connection with natural gas storage operations or conventional production of oil and gas. Thus, ECBM injection wells would likely be classified as Class II UIC wells.

2.7.4 Enhanced Oil Recovery Sequestration Permitting Requirements

In addition to the Class II injection well UIC permit, there are a number of other potential federal, state, and local permits, approvals, and authorizing actions that may be required for an enhanced oil recovery CO_2 geologic sequestration project. Some of these may include, but are not limited to, the following (DOI BLM, 2005):

- Onshore oil and gas orders: Permitting of operations (drilling - applications for permits to drill, completion, abandonment), drilling operations, site security, measurement of oil, flaring of gas, produced water disposal; includes wells, associated facilities, and roads.
- Oil and gas rules and regulations: State permits for drilling operations, safety regulations, pit permits, product measurement, and authorization of flaring, for wells and related facilities.
- State authorization of activities on state land: Approval of oil and gas leases, rights-of-way, temporary use permits, and developments on state land, for all facilities.
- RCRA: Permits for treatment, storage, or disposal of hazardous waste.
- Clean Water Act: Spill prevention, control, and countermeasure for transfer and storage of petroleum and petroleum fuels.
- State air quality permits: Permits for new or modified sources; prevention of significant deterioration, if applicable; control of HAPs, hydrogen sulfide, and VOCs; for all stationary fuel-burning sources, tanks, separators, dehydrators, and compressors.

2.7.5 Saline Formation Sequestration Permitting Requirements

As discussed previously for enhanced coal bed methane and enhanced oil recovery CO_2 geologic sequestration projects, respectively, existing UIC program regulations have specific requirements for the injection of fluids and gases in Class II wells associated with oil and gas production. These rules and regulations could readily be made to directly apply to CO_2 injection for EOR and ECBM purposes as part of a CO_2 geologic sequestration project.

However, there have been no commercial-scale applications of CO_2 geologic sequestration in saline formations in the U.S. to date, and the non-EOR injection of CO_2 in saline formations for sequestration purposes is not directly covered by the existing UIC program rules. Various potential regulatory options exist to cover non-EOR CO_2 injection wells, including incorporating existing natural gas storage statutes and regulatory frameworks, inclusion under Class I or Class V of the UIC program, reclassifying such wells as a subclass of Class II, or the creation of a new UIC classification (IOGCC, 2005).

Some view that among the five classes of injection wells, the most relevant to CO_2 injection into saline formations is the Class I wells (Tsang, 2004). The regulations for Class I wells are stringent and specific, while they are more flexible for Class II wells.

2.7.6 Co-Sequestration/IGCC Permitting Requirements

As there are only two fully integrated IGCC plants developed primarily for electricity generation in operation in the U.S., it is likely that any co-sequestration projects that inject CO_2 and H_2S acid gas developed in the U.S. by the 2013 time frame will involve a new, "greenfield" IGCC facility. Therefore, the various potential regulatory and permitting issues with developing a new IGCC plant with carbon capture and sequestration are described here. Some of these regulatory issues and permitting requirements could include, but not limited to, the following (UTBEG, 2005; Florida DEP, 2006; EPA 2006):

Utility Approvals

- Certificate of Public Convenience and Necessity: Approval by the state public utility or public service commission, certifying that the proposed IGCC plant is economical and meets the public need for additional efficient power generation.
- Facility siting approval: Approval by the state siting board that the proposed site is appropriate and the best among all alternatives with regard to environmental and other impacts.

Air Permitting and Regulatory Issues

- Fuel handling and preparation NSR permit for PM emissions (fugitive or point source); emission limits and/or PM control technology requirements.
- Gasifier exhaust particulate removal NSR permit for PM emissions; emission limits and/or PM control technology requirements.
- Combined cycle generation stack emissions NSR permit for NOx, CO, and VOC emissions; emission limits and control technology requirements.
- Potential cooling tower drift air emissions NSR permit for PM emissions, or demonstration of no contaminant release.
- Air separator unit stack emissions NSR permit for NOx emissions; emission limits and/or control technology requirements.
- Compliance assurance monitoring (CAM) for combined cycle generation stack emissions.
- NESHAP standard for hazardous air pollutants (HAPs).
- NSPS for combined cycle combustion turbine emissions.

Water Permitting and Regulatory Issues

- Groundwater management districts (including local requirements for sustainability) and surface water rights permits.
- Gasifier, and production water (fuel slurry mixture and steam generator), wastewater treatment and discharges: NPDES, pre-treatment and discharge to publicly owned treatment works (POTW), and/or UIC Class I discharge well permits.
- Cooling tower blowdown wastewater treatment: NPDES or POTW pre-treatment permits.
- Stormwater discharge of contaminated runoff: NPDES stormwater permits for construction and operation.

Waste Disposal

- Gasifier solid wastes: slag non-hazardous waste landfill permit or marketable byproduct, or ash potential RCRA hazardous waste requiring permit for storage and/or disposal.
- Gasifier exhaust particulate matter solid waste non-hazardous landfill permit.

- TRI annual reporting (e.g., for acid aerosols, ammonia, barium, chromium, HF, lead, manganese, mercury, nickel, nitrates, vanadium, and zinc).

Underground Injection/Sequestration of CO_2/H_2S

- UIC injection well Class I, Class II, or new classification permit.

2.8 FATE AND TRANSPORT OF CO_2 INJECTED INTO GEOLOGIC FORMATIONS

This section describes the predicted mobility and fate of CO_2 sequestered in geologic formations, based on existing field data, research and predictive modeling. Because data on the fate and transport of CO_2 in geologic formations is limited, this section does not cover fate and transport for all sequestration technologies. Therefore, the project examples, published papers and/or case studies provided here can illustrate some of the preliminary results of field studies or provide predictions regarding the general fate and transport of CO_2 in geologic formations.

Based on the body of work summarized and documented in the following sections, a number of general observations and conclusions can be made regarding the fate and transport of sequestered CO_2. These include the following:

- Depending on the type of formation involved, it appears that the maximum radial extent of the CO_2 plume from the injection well(s) should be on the order of 5-10 kilometers or less (< ~3-6 miles).
- For saline formations, significant dissolution of CO_2 in the formation water will help to limit the extent of the CO_2 phase plume, particularly in the 100+ year time frame.
- Geologic sequestration projects with well characterized formations, and well designed, constructed, operated, and monitored injection and post-operations systems, should be able to exhibit essentially no significant leakage.
- The greatest risk of leakage appears to be associated with abandoned wells.
- There are monitoring and mitigation technologies currently available that should be able to detect and remediate leaks of any major significance.

2.8.1 Overview of Fate and Transport Mechanisms

The type of geologic formation involved has a great degree of influence on carbon storage and transport. For example, coal seams have high potential for adsorbing CO_2 on coal surfaces. However, coal tends to swell in volume as it adsorbs CO_2, which can then restrict the flow of CO_2 into the formation. Oil and gas formations result from the presence of a structural or stratigraphic trap, which has been shown to reliably retain injected CO_2 (in the absence of leakage pathways). Saline formations suitable for carbon sequestration would need to be overlain by a reliable caprock. Basalt formations have the potential to mineralize injected CO_2 (forming carbonate minerals) that may effectively and permanently isolate it from the atmosphere, although large-scale field testing is required to confirm this potential.

Leakage of CO_2 from underground formations into the atmosphere or into overlying water supply aquifers is the leading concern associated geologic sequestration technology. The mechanism for leakage is highly dependent on the geological conditions of the storage structure and the uncertainties surrounding potential releases are great (Yammaoto et. al., 2004).

Porous formations themselves create a path for CO_2, but discontinuity of the formation, such as fractures or faults are more influential to the total permeability of the formation. Pathways and mechanisms for leakage can include:

- Failure of seal formations near the borehole (corrosion of formation rock, the casings, and the cement in the annulus).
- Leak through abandoned boreholes and wells.
- CO_2 migration through the seal formation due to its innate permeability.
- Seal structure failure by formation stress and pressure change caused by injection.
- Seal failure by external forces, such as tectonic forces, stress change caused by subsidence and sedimentation, earthquakes, etc (Yammaoto et. al., 2004).

Sites should be adequately characterized during the early project planning stage to identify any potential leakage pathways.

Overall, the fate and transport of CO_2 in geologic formations is highly dependent on site-specific conditions, such as geologic conditions, leakage pathways, chemical trapping mechanism, and formation pressure resulting from injection rates.

2.8.2 Fate and Transport – Transport Mechanisms and Predictive Modeling

2.8.2.1 "Storage Retention Time of CO_2 in Sedimentary Basins; Examples from Petroleum Systems" (Bradshaw, et al, 2005)

Thousands of billions of barrels of hydrocarbons have been trapped and stored in geological formations in sedimentary basins for 10s to 100s of millions of years, as has substantial volumes of CO_2 that has been generated through natural processes. If the same rigorous methods, technology and skills that are used to explore for, find, and produce hydrocarbon accumulations are now used for finding safe and secure storage sites for CO_2, the traps so identified can be expected to contain the CO_2 after injection for similar periods of time as that in which hydrocarbons and CO_2 have been stored in the natural environment.

It is anticipated that many of the risks and uncertainties associated with leakage from appropriately selected storage sites will become evident early in a project, long before significant volumes are stored. The most critical factor associated with leakage to the surface on human timescales will be from well bores rather than natural subsurface processes. Well bores can be monitored, maintained and remediation performed if required either before or during the injection operation, and as such this risk can be controlled. A remediation operation can readily be achieved within a 3 month period, which is insignificant in terms of leakage volumes when considered over the timeframe of either an injection period, or the total storage time. If injection sites are appropriately selected down dip from structural culminations, or hydrodynamic/solution traps are utilized as opposed to direct injection into depleted fields, then the likelihood of leakage failure from wells will be very much lower again. In such cases, injection pressures will have dissipated before the CO_2 gets to a leakage point, significant amounts of CO_2 will be trapped in closures with no well penetrations, and CO_2 will have dissolved into the formation water.

The timing of when leakage due to natural subsurface processes could occur post the injection period must also be borne in mind. If injection sites are chosen down dip from either structural culminations with well penetrations, faults or basin edges, then the time to migrate to leakage points could often be on the order of 1000s of years. Even if vertical migration results in the CO_2 permeating through imperfect seals, then there still will be tortuous pathways that the CO_2 will have to migrate through to reach the surface, and again this may be on the order of 1000s of years.

The above discussion suggests that leakage to the surface in human timeframes from appropriately selected storage sites will only occur in substantial volumes through old well bores that are not maintained and remediated, rather than through natural subsurface processes, and even then, there may be significant delay times before leakage to the atmosphere occurs. This suggests that future research effort should strongly focus on old well bores and how to make them safe and secure with non-corrosive components and materials, and the potential impact of subsurface leakage (out of the primary formation into a secondary shallower formation) and potential contamination effects that occur to subsurface resources (e.g., groundwater).

2.8.2.2 "Area of Review: How Large is Large Enough for Carbon Storage?" (Nicot, et al, 2006)

The Underground Injection Control (UIC) program defines the area of review (AOR) as the area surrounding an injection well described according to the criteria set forth in Section 146.06, or in the case of an area permit the project area plus a circumscribing area the width of which is either ¼ of a mile or a number calculated according to the criteria set forth in Section 146.06. Within the AOR, before starting any injection, an operator must identify all wells penetrating the injection zone or the confining zone and assess their status for possible corrective action. The overarching purpose of the AOR is protection of drinking water resources due to pressure buildup in the injection zone. Underground sources of drinking water (USDW) are defined as a formation with water quality below 10,000 ppm total dissolved solids. The AOR should be determined for each well or field through either a zone of endangering influence (ZEI) or a fixed radius, which cannot be smaller than ¼ mile. The radius of the ZEI is calculated as the lateral distance in which the pressures in the injection zone may cause migration of the injection and/or formation fluid into a USDW.

In Texas, as in most of the U.S., the fixed radius method is overwhelmingly used and is ¼ mile for Class II wells and 2.5 miles for Class I wells. Current requirements from the Railroad Commission of Texas for Class II wells include making best efforts to identify all wells in a ¼ mile radius of the proposed injection well and to provide evidence that all abandoned wells intersecting the injection formation have been plugged. The Texas Gulf Coast is an attractive target for carbon storage. Stacked sand-shale layers provide large potential storage volumes and in-depth leakage protection. However, multiple perforations resulting from intensive hydrocarbon exploration and production have weakened seal integrity in many favorable locations. If the ultimate goal of carbon storage is to isolate large volumes of CO_2 for hundreds to thousands of years, plume migration will encounter inadequately completed wells miles away from the injection zone. Even wells abandoned to current standards cannot be guaranteed leak-free in the long term.

Although the AOR has been traditionally defined by a fixed radius, with the strong regulatory requirement that the injectate stays within the injection layer, based on a "no-migration rule", buoyancy is a major characteristic of CO_2 that introduces a third dimension into the AOR process. Geological mapping was used to characterize some of the typical structural traps associated with the southern Texas gulf coast's progradational packages and growth fault zones, and well locations and salt dome footprints in the Corpus Christi and Houston areas. Likely CO_2 migration pathways and contacted volume of a migrating plume were determined, with the latter being potentially as large as a fault compartment with dimensions of up to 13 miles by 13 miles. However, the contacted volume is ultimately a function of the total injected volume, and the specifics of each project should dictate the dimensions of the zone of endangering influence. An option viable for the Texas gulf coast to reduce geologic uncertainty, to decrease the impact of wells, and to limit the amount of information to be collected is to inject CO_2 below the maximum penetration of most wells.

2.8.2.3 "Modeling the Sequestration of CO_2 in Deep Geological Formations" (Saripalli, et al, 2005)

Modeling the injection of CO_2 and its sequestration will require simulations of a multi-well injection system in a large formation field. However, modeling at the injection well scale is a necessary prerequisite to formation scale modeling. The models effectively simulate deep-well injection of water-immiscible, gaseous, or supercritical CO_2. The effect of pertinent fluid, formation, and operational characteristics on the deep-well injection of CO_2 was investigated. Formation permeability, porosity, injection rate and pressure, and dissolution of CO_2 influence the growth and ultimate distribution of the CO_2 phase. Deep-well injection of CO_2 is a multiphase flow phenomenon, where a slightly compressible supercritical fluid drives water radially outward, and also migrates upward due to buoyancy.

The CO_2 bubble growing during injection simultaneously dissolves in the formation waters and migrates upwards due to buoyancy. As a result, the CO_2 bubble recedes radially inwards, and floats toward the top confining layers. A set of simulations was run where CO_2 was injected for a period of approximately 3 years, and then allowed to dissolve and float. Immiscible CO_2-water contact, after the completion of buoyant floating and equilibrium dissolution, creates a region above this contact rich in free-phase CO_2 distributed radially. The injected CO_2 phase recedes radially and floats vertically upward, after a part of it being dissolved in the formation water. In the longer term, a part of this dissolved carbon may be permanently sequestered as a mineral phase, with the remaining mass being redistributed by dilution among the formation waters via advection and diffusion. The thin, free phase CO_2 layer floating at the top will serve as a source for diffusive flux into the formation waters, as well as potential escape into the overlying aquifer via fractures and high permeability conductive zones within the caprock. While the model can simulate the basic features of a typical CO_2 deep-well injection operation, it is based on the assumptions of uniform formation properties, and instantaneous dissolution of CO_2, which is likely to be a rate limited process. Apart from these limitations, these analytical approaches to the modeling of deep-well injection were shown to agree with earlier field data in natural gas storage applications.

After approximately 3 years of CO_2 injection, at a rate of approximately 150,000 tons/year, into a 160 meters thick formation, the radial distance from the injection well of the free-phase CO_2 bubble ranged from approximately 3–10 kilometers (or 2-6 miles), for formation porosities ranging from 10-30 percent. For the 30 percent porosity base case, free-phase CO_2 bubble radial distances ranged from approximately 3-18 kilometers (or 2-11 miles), for CO_2 injection rates ranging from approximately 150,000 to 1.5 million tons/year.

2.8.2.4 “Quantitative Estimation of CO_2 Leakage from Geological Storage: Analytical Models, Numeric Models and Data Needs” (M. Celia, et.al., 2004)

Comprehensive risk assessments are required to determine the overall effectiveness and potential environmental consequences of geologic carbon sequestration. An important part of these risk assessments are analyses of potential leakage of injected CO_2 from the formations in which it is injected into the atmosphere or other formations. Such leakage is a concern because it may contaminate existing energy, mineral, and/or groundwater resources, it may pose a hazard at the ground surface, and contribute to increased concentrations of CO_2 in the atmosphere.

Potential leakage pathways include diffusion across caprock formations, leakage through natural faults or fractures, and leakage through man-made features such as wells. The purpose of this paper was to develop large-scale mathematical modeling tools that can quantify potential CO_2 leakage along existing wells. The authors studied well locations in the Alberta basin to determine the spatial characteristics of well locations in a mature basin.

Injection of CO_2 into mature sedimentary basins could produce plumes that contact tens to hundreds of existing wells. Due to the fact that there is a broad range of length scales to be considered; a wide array of models is required that range from models of the geochemical degradation of well cements (cement plugs used to seal off abandoned wells) to models that include hundreds of existing wells over hundreds of square miles. Numerical models require very fine levels of detail, which would make modeling the effects of hundreds of wells a massive computational requirement. Therefore, in situations with large numbers of wells analytical solutions could be employed as a simplified approach.

The authors utilized an analytical approach to develop a mathematical technique capable of modeling a situation that encompassed a large number of wells over a large surface area, such as the Alberta basin.

This specific study of the Alberta basin showed that in areas with a high density of wells, an average of 240 wells would be contacted by a typical CO_2 plume that radiates on the order of 3.1 miles. However in background regions where wells are more sparsely located, approximately 20 wells would be contacted on average.

Because wells are continuous features, leakage through a well can result in leaked fluid contacting all formations along the well, as it proceeds toward the land surface and eventually reaches the atmosphere. The availability of permeable upper layers along the vertical column may attenuate the leakage as it proceeds.

The authors conducted models to determine relative leakage rates over time (27 years) where the leakage rate was expressed as a fraction of the CO_2 injection rate, normalized by the ratio of the permeability of the leaky well to the permeability in the injection formation. Their results indicate that the higher leakage rates in the leaky well induce stronger local decreases in pressure around the leaky well, which then induces increased brine flow into the leaky well. This "upconing" of brine into the well causes a much more gradual rise in the leakage rate for the CO_2, which corresponds to a much longer time period of two-fluid flow in the leaky well. The upconing around the leaky well causes a simultaneous flow of brine and CO_2 through the well, which has implications for the degradation of well materials. Well cement will degrade from acidified brine flowing past or through the cement. At higher CO_2/brine flow rates, the stronger upconing produces longer periods of acidified brine flow, which can lead to faster and more persistent degradation of well cements. This behavior provides a positive, non-linear feedback between the degradation and flow processes.

2.8.2.5 Multiphase CO_2 Flow, Transport and Sequestration in the Powder River Basin, Wyoming, USA" (McPherson, et al, 2000)

In this paper, the authors consider: (1) aqueous trapping, referring to the trapping of CO_2 by forming a groundwater plus CO_2 solution, leading to carbonic acid and dissociated ions, and (2) hydrodynamic or stratigraphic trapping: CO_2 moving into zones of high storage (porosity) and permeability, surrounded and trapped by zones of low permeability that restrict CO_2 escape. The Powder River Basin in Wyoming is a good example of a basin dominated by clastic units with interlayered carbonate formations. It was chosen for this CO_2 sequestration study because it is a typical intracontinental sedimentary basin, especially with regard to aquifer types, and its dominantly clastic stratigraphy and simple structure are helping to isolate relevant processes by minimizing complications due to structure and carbonates.

Numerical modeling analyses were conducted to evaluate flow, transport, and storage of groundwater and CO_2 in candidate aquifers of the Powder River Basin. In these numerical model simulations of the Powder River Basin, separate phase CO_2 was injected into the Fox Hills Sandstone at approximately 1,800 meters depth. By 750 years simulation time, saturation of separate phase CO_2 has decreased to less than 2 percent. Most of the CO_2 in the source has migrated away from the storage area and subsequently partitioned into solution in groundwater. Over the course of 1,000 years, CO_2 (both separate and dissolved phases) have migrated approximately 23 kilometers (or approximately 14 miles) away from the storage area. No CO_2 reached the ground surface within 1,000 years in any of the case study simulations. The primary general conclusion drawn from this modeling study is that regional scale sedimentary basin aquifers are viable candidates for CO_2 sequestration for time-scales of 103 years.

2.8.2.6 "Subsurface Sensitivity Study of Geologic CO_2 Sequestration in Saline Formations" (Flett, et.al., 2003)

Researchers with ChevronTexaco and Curtin University, Australia, conducted computer modeling of CO_2 in saline formations, assuming a high injection rate, under varying conditions. The model assumed a CO_2 injection rate of 120 mmscfd (6227 metric tons per day) equally distributed among 3 injector wells at a true vertical depth of approximately 7000 feet. Under the model, CO_2 would be injected for 30 years, after which only monitoring would occur. The key parameters that were varied in this screening study were:

- CO_2 solubility in brine
- Drainage relative to permeability curves
- Relative permeability hysteresis using:
  - pore size distribution parameter
  - Land's trapping constant
- Crestal fault leak/seal
- Saline formation volume

The study developed metrics for measuring sensitivity of a sequestration project to risk, estimated at different project times, via:

- The distance of injected CO_2 away from the injected location
- The volume of free CO_2 that exists in the formation in the CO_2 rich phase (i.e., not dissolved in formation waters)
- The size of the plume of CO_2 migrating up dip.
- The pressure change associated with the CO_2 injection at the crestal fault location.

These four measurements were developed to provide insight into the success of the proposed project during injection time. The migration distance of CO_2 is a key measure to show the probability of a plume reaching a leak point in the form of a non-sealing fault. The volume of free gas in the formation represents the amount of CO_2 not trapped by dissolution trapping and hence the amount of gas that remains as a potential leakage risk. The size of migration plume is a key measure of the success of gas trapping as permanent trapping mechanism and the risk associated with a volume of gas migrating to a leak point. The pressure change at the fault, relative to the base case model, gives a representation of the sensitivities associated with a pressure sensitive seal at a fault and potential risk of leakage through the fault to surface.

General Results and Observations:

- Low gas trapping and small formation size increase the migration distance of the gas. High gas trapping and larger formation size limits the extent of gas migration.
- The volume of the CO_2 plume has a strong relation to migration distance traveled. The larger the plume, the further the plume traveled up dip.

All cases after 30 years showed a migration distance of the gas from the injection points at approximately 2-3 kilometers (1.2 – 1.9 miles). The "very low gas trapping" case showed the highest migration of the gas from the injection points at the 8000 year mark at over 12 kilometers (7.5 miles). The case with "very high gas trapping", in contrast, showed a migration distance of only 3.5-4 kilometers (2.2 – 2.5 miles) at 8000 years. Overall, most cases showed a migration distance of 8-11 kilometers (5 - 6.8 miles) at 8000 years.

2.8.2.7 "Evaluation of the Spread of Acid-Gas Plumes Injected in Deep Saline Formations in Western Canada as an Analogue for CO_2 Injection into Continental Sedimentary Basins" (Bachu, et. al., 2005)

For 15 years, acid-gas (H_2S and CO_2) has been injected into deep saline formations at 24 sites in the Alberta Basin in western Canada. The acid-gas is injected at rates ranging from 1.8 metric tons per day to 900 metric tons per day, and at depths ranging from 3200 feet to 9300 feet. The total volume of injected gas was estimated to be between 9000 and 400,000 metric tons at the end of 2003.

The flow of the injected gas is dependent upon the hydrodynamic injection force and conditions, as well as density and viscosity differences between the injected gas and formation water. In order to assess the potential upward leakage of injected gas, the authors of this paper developed a mathematical model to predict the radial spread of an acid gas plume around an injection well. The analytical model showed that plume movement is dependent on formation characteristics such as: permeability, thickness, and porosity. Plume movement is also dependent on injection rate, fluid density and mobility.

The application of the developed model to the 24 injection wells in the Alberta Basin showed that the acid-gas plumes most likely migrated distances ranging from 490 to 6900 feet (1/10th to 1.3 miles) from the injection wells from the time of initial injection to 2003, depending on formation characteristics and volumes injected. The estimates of plume spreads were conducted assuming idealized injection conditions, through vertical, fully penetrating wells into horizontal aquifers of homogeneous characteristics. Also, it was assumed that the injected gas and formation water would not mix, which would produce an overestimation of plume spread. It is important to note that these assumptions do not reflect the natural reality of injection situations.

These distances, although evaluated with a set of simplifying assumptions, provide a good indication of the spread of the plume, and allow for the identification of wells that may potentially serve as leakage paths.

2.8.2.8 "Prediction of Migration of CO_2 Injected Into an Underground Depository: Reservoir Geology and Migration Modeling in the Sleipner Case (North Sea)" (P. Zweigel, et. al., 2000)

CO_2 separated from produced gas has been injected into an underground saline formation in the Sleipner area (North Sea) since 1996. The authors utilized seismic, wireline-log, and sample data as well as the SEMI hydrocarbon migration simulation tool to describe the formation's geology and to make predictions of the final distribution of injected CO_2 (20 MMT) over tens to hundreds of years.

CO_2 is injected near the base of the Miocene-Pliocene Utsira Sands. There are several thin shale horizons within the Utsira Formation that are expected to contain fractures and holes. The sands are highly permeable with porosities ranging from 27 percent to about 40 percent. The Utsira Sands are overlain by the Pliocene Nordland Shales, which are several hundred meters thick and are expected to act as a seal.

The results of the simulation produced two potential final CO_2 distributions: 1. Assuming the top Utsira Sand acts as a long-term barrier the injected CO_2 should migrate in a north-westwards direction reaching a maximum distance of about 12 kilometers (7.5 miles) to the injection site; 2. If the shale layer above the Utsira Sand leaks and CO_2 invades the sand wedge above, migration would occur in primarily a north to north-eastward direction, however a prediction of the maximum migration distance could not be ascertained because the CO_2 would leave the area studied at a point 7 to 10 kilometers (4.3 to 6.2 miles) from the injection site. At the time of this research, preliminary time-lapse surveys indicated that a small fraction of CO_2 may have migrated into the sand wedge.

The modeling revealed that realistic simulation of the fate of CO_2 in such sites required large grid dimensions, very high lateral and vertical seismic resolution, the incorporation of formation heterogeneity, the representation of several temporary and final migration barriers within one model, and the need to run several alternative models.

2.8.2.9 "Reactive Transport Modeling for the Long Term CO_2 Storage at Sleipner, North Sea" (Audigane, et al, 2005)

For this research, the geo-chemical impact of the CO_2 injection on the Sleipner formation is investigated using reactive transport modeling, performed both for the injection phase as well as the long term storage period (several thousand years). The models are initially run in kinetic batch mode in order to determine the principal geo-chemical reactions in the formation due to the presence of CO_2. In a second step, fully coupled reactive transport modeling is performed in order to calculate the evolution of the CO_2 plume in space and time as well as the geo-chemical impact on the formation. The simulations are performed for a period of time of 10,000 years, including 25 years of CO_2 injection. Simulation results predict low chemical activity in the formation with the injected CO_2, according the chosen mineralogy and the initial formation water. The major part of CO_2 is trapped as supercritical gas (structural trapping) and as dissolved gas in the brine (dissolution trapping).

Repeat seismic surveys have shown that the injected supercritical CO_2 moves, due to buoyancy effects, upward from the injection point and accumulates under the overlying caprock and shale layers. A near steady state flow upwards to the top of the formation seems to have been reached by 2001, and most of the CO_2 injected from 2001 to 2002 has spread laterally at the mid and the top level. This recent time-lapse seismic data show no indication of leakage at the Sleipner CO_2 injection site.

The modeling shows that after 25 years of injection, the supercritical CO_2, which is lighter than the brine, reaches the top of the formation and the gas bubble extends laterally up to 500 m away from the injection well, except at the top where the CO_2 accumulates and extends up to 1500 m (approximately 1 mile). The semi-permeable layers induce some accumulation of CO_2 beneath them without stopping the upward migration. Hence, after 100 years, almost all the supercritical CO_2 has reached the top of the formation while dissolving in the brine.

The density of the liquid phase during progressive CO_2 dissolution becomes higher than that of the initial brine and CO_2-loaded brine migrates downward. This density contrast is smaller than that between the supercritical CO_2 and the initial brine, explaining why one can observe that the downward migration of aqueous CO_2 occurs much slower than the upward migration of supercritical CO_2. This mixing of aqueous CO_2 in the liquid phase tends to accelerate the dissolution process and after 5,000 years almost all the supercritical CO_2 has been dissolved, while it is completely dissolved after 10,000 years.

2.8.2.10 "Reactive Geochemical Transport Simulation to Study Mineral Trapping for CO_2 Disposal in Deep Saline Arenaceous Aquifers" (Xu, et al, 2003)

A reactive fluid flow and geochemical transport numerical model for evaluating long-term CO_2 disposal in deep saline formations has been developed. Using this model, the authors performed a number of sensitivity simulations under CO_2 injection conditions for commonly encountered Gulf Coast sediment to analyze the impact of CO_2 immobilization through carbonate precipitation.

A one-dimensional radial model was used. This simplification justification can be derived from the slow rates and long time scales of geochemical changes which will allow processes to be played out that over time will make the distribution of CO_2 more uniform. Initially, injected CO_2 will tend to accumulate and spread out near the top of permeable intervals, partially dissolving in the aqueous phase. CO_2 dissolution causes aqueous-phase density to increase by a few percent; this will give rise to buoyant convection where waters enriched in CO_2 will tend to migrate downward. The process of CO_2 dissolution and subsequent aqueous phase convection will tend to mix aqueous CO_2 in the vertical direction. The time scale for significant convective mixing is likely to be slow (of the order of tens to hundreds of years), and may be roughly comparable to time scales for significant geochemical interactions of CO_2.

The well field was modeled as a 100 meters thick circular region of 8 kilometers (~5 miles) radius and 10 percent porosity, into which CO_2 was injected uniformly at a constant total rate of approximately 3.5 million tons/year (approximately equal to the generation of a 286 MW coal-fired power plant). The CO_2 injection was assumed to occur over a period of 100 years. The fluid flow and geochemical transport simulation was run for a period of 10,000 years. Simulation model results indicate that the CO_2 plume extends out about 6 kilometers (~3.75 miles), for both the 100 and 10,000 year cases, with CO_2 saturations of 40-50 percent occurring in the approximately 50-500 meter distance order of magnitude. CO_2 in the gas phase remains roughly 2-3 times that in the aqueous phase for the first 1,000 years, with the precipitation of a carbonate solid phase beginning to occur after approximately 500-1,000+ years. The simulation was partially validated by field observations of the diagenesis of Gulf Coast sediments, and in particular, sandstones of the Frio formation of Texas. Although the current model does not entirely replicate conditions in the field, the results are generally in agreement.

2.8.2.11 "Modeling of the Long-Term Migration of CO_2 from Weyburn" (Zhou, et al, 2004)

In July 2000, a 4 year research project to study geological sequestration and storage of CO_2 was launched, known as the International Energy Agency (IEA) Weyburn CO_2 Monitoring and Storage Project. CO_2 from the North Dakota Gasification plant is transported and injected into an approximately 1450-meter (4750 foot) deep oil formation located in Weyburn, south Saskatchewan, Canada, for enhanced oil recovery. The operator, Encana Resources of Calgary, Alberta, has designed a total of 75 patterns, over approximately 320 acres, for this operation that will last for approximately 34 years.

One of the objectives of this multi-disciplinary project has been to determine the long-term fate of CO_2 injected into the formation. Such a determination involves an evaluation of the potential for CO_2 to migrate to the environment via both natural and man-made (wellbore) pathways. Within a systems analysis of the base scenario of the storage system, CO_2 is expected to migrate via natural (geosphere) and man-made (abandoned wells) pathways under pressure, density, and concentration gradients. Mass partitioning of CO_2 among the three phases accompanies movement of fluids.

The model includes ten formations and six flow barriers from about 100 meters (330 feet) below the Weyburn formation to the ground surface, or about 1800 meters (approximately 6,000 feet) of sedimentary rocks. The lateral extent of the model is approximately 10 kilometers (6 miles) from the EOR boundary, including the formation outside the EOR patterns, as established by previous scoping assessments. The assessment period starts at the end of EOR operation and extends to 5000 years thereafter.

The geosphere migration model considers three phases (oil, gas, and water), and seven components including CO_2 and six pseudo hydrocarbon components. The modified Peng-Robinson equations-of-state are used to dictate fluid phase behavior and component mass partitioning. The migration model uses default CO_2 solubility data, which originate from an empirical relation valid at low pH values and are applicable to most formation conditions. The long-term assessment begins at the end of EOR (in 2034), taking into account the CO_2-in-place, as well as pressure and fluid/component distributions in the field, predicted for the EOR period by independent formation simulation. The caprock is treated as permeable material with non-zero permeability.

Based on the simulation modeling, the CO_2-rich gas phase moves from the bottom to the top of the formation and is trapped under the caprock due to the entry pressure effect and low permeability in the caprock. Oil phase also moves updip accompanied by diffusion of hydrocarbon components (excluding CO_2) from the surrounding formation into the EOR area where much oil has been produced. By diffusion, CO_2 in oil phase moves away from the EOR patterns, which is opposite to the hydrocarbon component movement. Both oil and gas phases inside the 75 patterns, however, are less mobile than the water phase, and are largely confined within, and in the vicinity of, the 75-pattern area. The trapped gas phase forms gas pockets scattered in the 75-pattern area. The gas pockets shrink with time due to loss of CO_2 by dissolution in the moving water. Water movement is driven by pressure gradient during the early depressurization (the process of equilibrium between high EOR residual pressure and the ambient pressure that is in hydrostatic range) period and subsequently is controlled by the ambient flow field after pressure gradient. The CO_2-bearing water that is denser also moves downward. Constant formation water sweeping the 75-pattern area picks up CO_2 from less mobile oil and gas phases, carrying dissolved CO_2 laterally outward and also downward.

Cumulatively, after 5,000 years, the total amount of CO_2 removed from the EOR area is 26.8 percent of the initial CO_2-in-place at the end of EOR (the CO_2 in the 75 patterns at 2034 is 21 MT). Among that, 18.2 percent of the initial CO_2-in-place is released into the geosphere below the formation, 8.6 percent ends up in the formation outside the EOR area, and 0.02 percent goes to the geosphere above. No CO_2 enters any potable aquifer over the 5000-year period. Results from these simulations demonstrate that key parameters affecting CO_2 vertical movement include the caprock permeability and the entry pressure, and indicates the important contribution of the multiple thick barriers above the formation.

The base scenario also defines man-made pathways for CO_2 migration as the existing wells plus those drilled prior to the completion of EOR, all of these abandoned upon completion of EOR. Abandoned wells, although sealed upon abandonment, may provide potential pathways for the injected CO_2 to return to the surface due to degradation of the sealing materials. There are thousands of wells within the study area, the lateral extent of the geosphere migration model. Most of these wells are located outside the 75-pattern area. The geosphere migration results have shown that high CO_2 concentrations in all three phases occur within, and in the vicinity of, the 75 patterns; hence, the focus area for the well leakage assessment is in the center area of the geosphere model that includes the 75 patterns and vicinity. Within the perimeter of this focused area, there are more than 800 existing wells and more are likely to be drilled.

Key assumptions of this modeling approach include: (1) cement seal degradation corresponding to an increase in permeability from 0.001 mD initially to 1 mD at 100 years; (2) no loss of CO_2 to flow inside the formation as well as within the formations surrounding the wellbore; and (3) fast transport of CO_2 once it enters the borehole, i.e., rapid ascent of CO_2 to the surface as gass bubbles. These assumptions result in a conservative assessment, by overestimating CO_2 leakage rates, given the variability and uncertainty of the key parameters used in the model.

With a maximum CO_2 flux modeled through a wellbore of 0.016 kg/day, with an estimated 1,000 wells over the 75-pattern area, yields a total cumulative leakage of CO_2 of ~0.03 MT over 5,000 years. This total amount represents approximately 0.14 percent of the total CO_2-in-place (21 MMT) at the end of EOR. This value is a highly conservative upper estimate, however, as it assumes that the maximum flux is maintained throughout the entire 5,000 year period for all wells. A more representative value is the mean cumulative leakage, corresponding to less than 0.001 percent of the CO_2-in-place at the end of EOR.

These results mean that if the Weyburn CO_2 storage system evolves as expected, the goal of storing greenhouse gas CO_2 can be achieved. Future assessments should focus on alternative scenarios, including seismic activity, open wellbores, and human intrusion.

2.8.3 Fate and Transport – Project Results

2.8.3.1 "Surface Environmental Monitoring at the Frio CO_2 Sequestration Site, Texas" (Nance et al., 2005)

At the Frio Brine Pilot site near Dayton, Texas, surface and near-surface environmental conditions were monitored from the start of CO_2 injection for nine months at the time of reporting. The purpose of the monitoring was to detect CO_2 leaks and associated perfluorocarbon tracers that were injected into the Frio Formation sandstone at a depth of 5,050-ft. Monitoring efforts are on-going and consist of in-field measurements and sampling for laboratory analyses of shallow groundwater and gases that accumulate in water-well headspaces and soils. Shallow Beaumont Formation groundwater hydrochemistry and headspace gases are monitored in four 95-ft wells by field probes, laboratory analyses, and capillary absorption tubes (CATs). Soil gases are collected using hypodermic syringes in four 5-ft deep, sealed dry wells; by CATs placed in 40 0.3 to 1 m deep tubular aluminum installations; and with a portable accumulation chamber, which gases are collected from.

Shallow groundwater pH, electrical conductivity, and alkalinity measurements have varied, however the information is ambiguous with respect to the potential leakage of CO_2 and CH_4. Variability in meteorological conditions may be responsible for the hydrochemical variability.

Because the site is heavily vegetated, temperate and located near marginal wetlands, detection of CO_2 leaks is challenging because of the abundant decaying organic matter. The study concluded that pre-injection baseline data must be developed over time intervals of sufficient length to document the natural cyclic and episodic variations in environmental parameters, in order to accurately discern formation CO_2 leaks.

2.9 LIABILITY ISSUES RELATING TO CARBON SEQUESTRATION

The legal system for addressing liability for a carbon sequestration accident is not mature, there is little case law to draw upon, and legislation to specifically address carbon sequestration liability has not been enacted.

For geologic sequestration, surface leakage and potential risk to human and the near-surface environment is the most important class of risks to be managed, whereas protection of groundwater – the focus of current regulation – is likely to be a substantially less important risk than for current hazardous waste injection. In addition, geologic sequestration raises issues due to large-scale fluid displacement, as well as monitoring and verification that are (arguably) less relevant in the context of more familiar disposal activities (Wilson, et al, 2004).

Because property law in the U.S. is predominantly an issue of state law, there are irregularities between jurisdictions concerning the property interests of geologic CO_2 storage. In particular, there are three key areas of distinction: (1) the distinction between ownership rights needed for injection of CO_2 into a mineral formation and rights needed for injection into a deep saline formation; (2) the distinction between voluntary and involuntary methods of acquisition; and (3) the distinction between ownership of the geologic formation and ownership of the injected CO_2. Although common law concerning natural gas storage will serve as precedent for establishing property interests over CO_2 storage, the issue remains whether federal or state legislation of natural gas storage will govern CO_2 storage (Figueiredo, 2005).

In the gas storage model, the surface owner owns the subsurface storage pore space, while mineral rights owners may have an interest in the residual gas. The gas storage operator retains rights to the stored gas, and must obtain rights to the entire formation. Others cannot produce the gas even if it escapes onto adjacent lands for which rights are not owned. The power of eminent domain is generally available. It is not clear at present if this model would work for CO_2 storage. If so, valuation of the storage rights becomes the key question that must be determined (Van Voorhees, 2006).

EPA's regulatory approach had been based on permit by rule for natural gas storage, based on the "inherent economic incentive" that "reduces the need for scrutiny of these operations"; EPA noted at the time that "the subsurface storage of hydrocarbons is practical only if a preponderant portion of the stored resource can be recovered when desired (44 Fed. Reg., April 20, 1979). The question regarding long-term CO_2 storage is whether the same economic case be made, and do similarly compelling economic incentives (such as credits) apply to containment. The final conclusion will likely be driven by EPA's determination on this issue, with their subsurface injection interpretations having prevailed previously (Van Voorhees, 2006).

The intersection of risk and liability is also an important consideration. Short-term risk might be handled by standard liability, but long-term risk, occurring decades or centuries after the end of the injection phase of the operation will have to be handled in an entirely different manner. Companies do not "live" long enough to make private liability an acceptable policy, especially as even long-lived companies often transfer their outstanding liabilities to smaller companies with shorter life spans. Due to the long sequestration times (most likely hundreds of years), and the relatively short lives of most businesses, it seems clear that some type of transfer of liability to public hands must be made, though how orderly this is and what form it will take could significantly affect private investment in geologic sequestration. How company bond ratings, along with insurance and re-insurance industries are affected by geologic sequestration risk exposure and liability could have an important influence on technological deployment (Wilson, et al, 2004).

An example of one government's response to this issue is in Australia, where the Ministerial Council for Minerals and Petroleum Resources (part of the Commonwealth's Department of Industry, Tourism, and Resources) has issued a draft guiding regulatory framework for regulating geologic sequestration. One element of their framework addresses long term responsibilities. They indicate that, following closure, primary responsibility for the site will lie with the government, although some residual liability may remain with the project proponent. The scope and nature of these residual responsibilities will be resolved upfront, determined and negotiated with the proponent on a project-by-project basis. There may be a need to manage any residual liability that remains with the proponent, for example, through means such as ongoing indemnities, insurance policies, or trust funds (MCMPR, 2004)

As with any industrial project, carbon sequestration has certain risks that are inherent that may lead to liability for damages should an accident or unintended release of CO_2 occur. Standards of liability is a legal concept that establishes the system for resolving claims due to potential liability. Claims for damage could be brought on the basis of negligence, strict liability, implied warranty, or product liability. A claimant could pursue a claim in federal, state, local or even international jurisdiction depending on the nature of the claim.

The consideration of property interests and associated liability is fundamental to carbon capture and sequestration operations. Property interests play a role in determining the cost of geologic storage through the acquisition of necessary geologic formation property rights and the value of storage through ownership of injected CO_2. The determination of property interests will also have implications for long-term liability of any CO_2 emitted to the atmosphere in the future. Liability concerning property rights may derive from several theories, including geophysical surface trespass, geophysical subsurface trespass, or liability from commingling of goods. Geological CO_2 storage faces two potential types of geophysical subsurface trespass: subsurface trespass that results in production or drainage of stored CO_2 from the storage formation, and trespass caused by underground intrusion of injected CO_2 (Figueiredo, 2005)

Legislation on the state or federal level concerning property interests and eminent domain power may provide clarification over property interests and liability of geologic storage of CO_2. Federal or state eminent domain legislation specific to geologic CO_2 storage would be necessary to obtain property rights to the geologic formation by involuntary means. In addition, although property interest and liability for mineral rights have traditionally been addressed by common law, there exists the potential for legislation to define the circumstances of ownership and trespass. Eminent domain legislation and property rights clarification could be done on either the state or the federal level. Federal legislation would be limited to those circumstances where the CO_2 storage is deemed to be within interstate commerce or having a substantial effect on interstate commerce (Figueiredo, 2005).

Claims for damage could be brought on the basis of negligence (failure to execute "reasonable care"); strict liability (imposed for "abnormally dangerous" activities, regardless of reasonable care); implied warranty (fitness for a particular purpose); or product liability (manufacturing/design defects, or failure to warn of possible danger). A claimant could pursue a claim in federal, state, local or even international jurisdiction depending on the nature of the claim.

"During the operational phase of the CO_2 storage project, the responsibility and liability for operational standards, release, and leakage mitigation lies with either the owner of the CO_2, established through contractual or credit arrangements, and/or the operator of the storage facility. Long-term ownership (post-operational phase) will remain with the same entities" (IOGCC, 2005). However, given the nonpermanence of responsible parties over long time frames, oversight of carbon capture and geologic sequestration projects will require creation of specific provisions regarding financial responsibility in the case of insolvency or failure of the licensee. The IOGCC Task Force believes that this assurance ultimately will reside with federal and state governments cooperatively through the establishment of specialized surety bonds, innovative government and privately backed insurance funds, federally guaranteed industry-funded abandonment programs, government trust funds, and public, private, or semi-private partnerships. Following completion of the injection phase, a regulatory framework needs to be established to address long-term monitoring and verification of emplaced CO_2, leak mitigation for the stored CO_2, and determination of long-term liability and responsibility.

A public permitting process must balance competing goals: it should be objective, transparent, and open to public input; also, it should be able to deliver closure in the form of definitive answers over a reasonable period of time. A geologic sequestration protocol should combine performance-based and prescriptive rules. This approach would allow for orderly decision making about specific projects using prescriptive rules, while allowing for public debate about the ability of prescriptive rules to ensure that permitted projects comply with overall performance goals. This type of hybrid system could allow for the integration of new knowledge into the regulatory process and give operators more flexibility in pursuing a performance-based approach for certain programmatic aspects or a prescriptive approach where data is more uncertain (Wilson, et al, 2004).

The oil and gas exploration and production industry has faced liability issues throughout the history of the industry some of which are similar to those associated with the risks of carbon sequestration. Liability will also depend on mineral property rights, which vary from state to state. A firm seeking to store CO_2 in a specific geologic formation would need to know who owns the rights to the formation, and what those specific rights entail. There may be analogous experience in the underground natural gas storage industry, where companies inject and store natural gas in underground formations. The industry has found that entities with potential property rights include the land surface owner, the mineral interest owner, the royalty owner, and the reversionary interest owner (interest in a formation that becomes effective at a specified time in the future). Several types of liability can be considered as described by Figueiredo, et. al. (2005) and summarized here.

The following phases of carbon sequestration have their own different liabilities: Operational, In-situ, and Climate.

- **Operational liabilities** are those associated with the technology of carbon capture, gas processing, gas compression, transport, and injection. Commercial operations have operated successfully with the risks of this segment of sequestration including transportation of CO_2 and EOR in oil fields. Accidents have occurred but have been handled within the current system of laws, regulations, and case law. Operators have recognized the risks and the rewards for each project.
- **In-situ liabilities** are those related to the potential leakage of CO_2 from a subsurface geologic storage facility. The risks of leakage are health impacts, potential fatalities, and unintended carbon releases to the atmosphere. “Once carbon dioxide exits the injection well and enters the geologic formation, its transport and fate are governed by in-situ processes. The choice of appropriate sites is the best way to minimize any adverse effects related to carbon dioxide storage. However, there is a potential for leaks of carbon dioxide from the geologic formation to the surface, migration of carbon dioxide within the formation, and induced seismicity (Heinrich, et. al., 2003). Potential sources of liability include public health impacts, and environmental and ecosystem damage.” (Figueiredo, et al., 2005).
- **Climate liabilities** are those from the secondary impacts of carbon releases and global warming. These liabilities would be much more difficult than the others to assess and litigate.

There are two property interests of significance in determining ownership of the geologic storage formation that has contained oil, gas, or coal. The first is the mineral interest, which comprises the right to explore and remove minerals from the land. The mineral interest may be associated with a royalty interest, which is the right to receive a share of the exploited mineral proceeds. Most states regard a mineral interest as including not only stationary minerals such as coal, but also fugacious minerals, such as oil and gas, unless intent to the contrary is expressed. The second property interest of significance is the surface interest, which consists of all other ownership in the land. In the majority of states in the U.S., the owner of the surface interest owns the geologic formation (Figueiredo,et al 2005).

The determination of property rights over a saline formation is comparable to the mineral formation case. In the majority of states, the owner of the surface interest has the right to make any use of the subsurface space, including the saline formation. Just as in the case of a mineral formation, where ownership of non-depleted minerals must be accounted for, any storage operation needs to take into account ownership of the water contained in the saline formation. Unlike the mineral rights case, however, there are a number of property regimes that states use to determine property rights over the water. In addition , there is an inherent uncertainty concerning the determination of property rights for a saline formation with respect to CO_2 storage because of the lack of case law on point. Instead, the law has focused on property rights over the taking and use of groundwater for consumption (Figueiredo, et al., 2005).

With the onus currently on private industry regarding liability, there may be a need for the federal government to establish legislation to protect the assets of and cap the value of claims brought against companies that would conduct sequestration projects similar to approach taken in the Price-Anderson Act of 1957 (42 U.S.C. § 2210 et seq.). Price Anderson established a framework for payments to the public in case of a nuclear accident. Moreover, assuming the liability for carbon storage is judged low enough, some insurance companies may be willing to bear the risk. Insurance companies will gravitate to situations where risk categories can be pooled, or where the likelihood of accidents can be predicted. The availability of insurance will depend on assessments of the risk of CO_2 leakage from a geologic formation (Figueiredo, et al., 2005).

A “liability cap” may be a double-edged sword for carbon storage. On one hand, it would provide industry with some certainty as to the financial liability associated with any leakage. On the other hand, a liability cap could be detrimental to carbon storage from a public perception standpoint. Liability caps are quite rare and are generally reserved for areas of real catastrophic risk. They are also necessary for situations where no insurance company would be willing to bear the full damages of disaster. For example, in addition to nuclear accidents, Congress has authorized a $100 billion cap on terrorist-related losses by the Terrorism Risk Insurance Act (15 U.S.C. § 6701 et seq.). It is likely that liability caps could stigmatize carbon storage by associating its risks with those of high-level nuclear waste and terrorism (Figueiredo, et. al., 2005).

Another example for liability management is the EPA’s underground injection control (UIC) program. The owners of Class 1 injection wells used for disposing of hazardous waste must demonstrate evidence of financial ability to pay from claims that could stem from the operations. In this situation, the liability remains with the owners and operators of the injection wells. Under the UIC program, permitting and monitoring requirements are implemented to prevent contamination and safeguard potable water sources. However, there still exists the potential for wide-spread harm to human health and the environment. Because of this potential liability, operators of UIC wells for geologic sequestration can minimize their liability through identification of potential migration pathways during the design phase, proper well construction, testing and monitoring of well and seal integrity, and regular and long-term monitoring of injected gases.

Injecting CO_2 into oil and gas formations poses some liability problems because the injection might conceivably interfere with mineral and resource ownership rights. Unitization of oil and gas formations has addressed this concern, but not all fields are unitized. Even in the absence of unitization, claimants have been generally unsuccessful in recovering liability damage claims for water floods. There are no guarantees that CO_2 storage would produce the same liability results if valuable resources are damaged or driven away (Van Voorhees, 2006).

The release of CO_2 from pipelines is also an area of potential liability. Records have been kept by the Office of Pipeline Safety regarding accident history of hazardous liquid pipelines over the last 2 decades. Some leading causes for these accidents are shown in Table 2-43.

Table 2-43. Hazardous Liquid Pipeline, Accident Summary by Cause (2002-2003)

Reported Cause	Number of Accidents	% of Total Accidents	Barrels Lost	Property Damages	% of Total Damages	Fatalities	Injuries
Corrosion	72	26.3	57,160	$18,734,697	24.8	0	0
Materials or Weld Failure	45	16.4	41,947	$30,760,495	40.6	0	0
Equipment Failure	42	15.3	5,717	$2,761,068	3.6	0	0
Excavation	41	15.0	35,220	$9,207,822	12.2	0	0
Other	36	13.1	19,812	$8,918,974	11.8	1	1
Natural Forces	13	4.7	5,045	$2,646,447	3.5	0	0
Operations	13	4.7	8,187	$602,408	0.8	0	4
Other Outside Force	12	4.4	3,068	$2,062,535	2.7	0	0
Total	274	100.0	176,156	$75,694,446	100.0	1	5

Notes:
The failure data breakdown by cause may change as the Office of Pipeline Safety receives supplemental information on accidents.
Sum of numbers in a column may not match given total because of rounding error.

Source: OPS, 2005.

As shown in Table 2-43, most accidents and property damage associated with hazardous liquid pipelines are caused by corrosion or materials/weld failure. The next leading causes of these pipeline accidents are equipment failure and excavation. Although this accident data covers all types of hazardous liquid pipelines, it could be a good indicator of the causes and accident rates for CO_2 pipelines. Subsequently, operators of CO_2 pipelines should be able to avoid many of these accidents, and subsequent liability issues, through adequate corrosion control design, diligent pipeline monitoring, proper maintenance and other prevention strategies.

Between 1995 and November 2005, there have been only 12 CO_2 pipeline accidents reported, one of which carried sour CO_2 (See Table 2-44). In comparison, there were over 960 natural gas pipeline accidents during the same time period. Although there frequency of CO_2 pipeline accidents is rare, this can be attributed to the relatively few miles of CO_2 pipeline currently in the U.S. Using natural gas pipeline accident data as a benchmark for comparison, over the last 10 years natural gas pipeline accidents averaged $484,000 in property damages per incident, whereas CO_2 pipeline accidents resulted in less than 1/10th this property damage, at an average of $42,000 per incident (OPS, 2005). For this same reporting period, natural gas pipeline accidents resulted in 82 injuries and 29 fatalities, whereas the CO_2 pipeline accidents resulted in no injuries or fatalities. Table 2-45 lists CO_2 pipeline accident statistics through November 2006.

Table 2-44. CO_2 Pipeline Accident History Compared with Natural Gas Pipelines

Type of Pipeline	Number of Accidents (1995 – Nov 2005)	Property Damage	Number of Fatalities	Number of Injuries
CO_2	12	$505,292	0	0
sour CO_2	1	$3,360	0	0
natural gas	967	$467,925,347	29	82

Table 2-45. CO_2 Pipeline Accident History, 1990 - 2006

Year	No. of Accidents	Barrels Lost	Property Damages	Fatalities	Injuries
2006b (1% H_2S)	1	100	$0	0	0
2006a	1	307	$559	0	0
2005	1	2,394	$3,880	0	0
2004	2	8,180	$73,430	0	0
2003	none				
2002	2	3,912	$10,430	0	0
2001	1	18	$11,052	0	0
2000	1	83	$371,000	0	0
1999	none				
1998	none				
1997	1	1,159	$2,000	0	0
1996	3	4,499	$33,000	0	0
1995	1	0	$500	0	0
1994	3	6	$51,696	0	0
1993	none				
1992	none				
1991	none				
1990	none				

Source: OPS, 2007.

For the DOE sequestration program, the government would probably have little liability should a sequestration funded project result in a claim. This is because the federal government is protected through the principle of sovereign immunity so that states and individuals can litigate against the federal government only if the government allows the case to proceed. This implies that the companies or institutions that would perform a sequestration project using DOE funding would not be indemnified by the federal government.

Consideration of long-term liability is a key element in assessing the viability of geologic carbon storage. The way in which liability is addressed may have a significant impact on costs and indirectly on public perceptions of geologic storage. Liability itself is not a new topic; indeed, operational liability of CO_2 injection is handled routinely in the oil and gas industries as a part of doing business. Whether liability for geologic carbon storage will be treated like the historic treatment of natural gas which has imposed relatively low costs on operators, or more like hazardous waste which has been much more burdensome to participants (and much more politicized) is uncertain (Figueiredo, et al, 2005). Other major outstanding legal issues include short-term measurement, monitoring, and verification; long-term monitoring and management; long-term liability for operation and leakage; and remediation methods and responsibility (Van Voorhees, 2006).